Secondary Treatment Facilities Plan

Volume III
Appendix H

Energy

January 12, 1988

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new electric motor-driven pumps as part of the new primary treatment plant construction program.

At the Winthrop Terminal headworks, there are four electrical-driven 15-mgd sewage pumps and two diesel-driven pumps rated at 60 mgd. The diesel drives will be replaced with motor drives as part of the Fast-Track Improvements Program.

1.2 ENERGY DEMAND PROJECTIONS

Table H-1 shows the estimated peak power demands for the years 1987 to 1999 for the Deer Island facility together with the committed (existing or already planned) capacity discussed above. These power requirements are based on total electrification of the influent pumping station and new treatment facilities. The demand or need increases in a stepped manner from current peak, cumulative electric demands of 2,150 kw to 45,200 kw in 1995 (full primary treatment of both North and System Systems), and 64,225 kw in 1999 (secondary treatment). Based on historical pumping profiles, a preliminary power-load duration curve was developed, as shown in Figure H-1, to characterize hourly electric energy consumption. Estimates of thermal energy demand were developed for heating buildings and pipe galleries in each alternative and for heating sludge in the anaerobic digester alternatives.

1.3 POWER SUPPLY ALTERNATIVES

During the preliminary power supply alternatives study, three options were considered. The first was to purchase all additional energy, primary plus backup, from a local utility. The second was to add sufficient generating capacity to meet the entire requirement with the largest unit out of service, which would require no connection with the local utility. The third involved purchasing all energy from a single source and adding sufficient generating capacity to supply all required energy should the tie with the utility fail in service.

At the time that the Preliminary Energy Report was discussed with the MWRA Board of Directors, the Board voted to eliminate Alternative 2 (i.e., 100 percent on-island generation of Deer Island power requirements). This alternative, was, therefore, deleted from further consideration. It was further decided that meetings would be held with both Boston Edison Company (BECo) and Massachusetts Electric Company to determine which could satisfy both the peak demand and EPA's reliability criterion, which requires the provision of power from two separate sources to meet uninterrupted critical service needs. Deer Island is currently within BECo's licensed service area.

Based on the vote of the MWRA Board and the estimated power demands, the following basic power supply alternatives (Alternatives 1 and 3) for primary and backup power for Deer Island were considered further.

Alternative 1: Off-site Purchase. BECo would supply most of Deer Island's power requirements via a dedicated transmission line from its K Street substation. A duplicate transmission line from its Chelsea substation would be provided for backup. No additional on-site generating capacity beyond the two 6 MW dual fuel diesels is proposed.

TABLE H-1

PRELIMINARY POWER NEEDS OF SECONDARY TREATMENT FACILITIES PLAN

Year	Description of power needs	Incremental increase to average load (kw) period	Cumulative average load (kw)	Peak load (kw) period	Cumulative peak load (kw)	Cumulative installed capacity (kw)	Cumulative secure capacity* (kw)	Cumulative shortfall (kw)
1986	One electrified influent pump	1,500		1,500		3,500	2,800	
1986	Basic power usage	650	—	650	—	—	—	—
			2,150		2,150	3,500	2,800	0
1988	Electrification of four influent pumps (additional) and Winthrop terminal pumps	2,500		7,200		12,000	6,000	
			4,650		9,350	15,500	8,800	550
1990	Construction power	10,000		15,000		0	0	
			14,650		24,350	15,500	8,800	15,550
1991	Primary sludge-dewatering, piers and basic power	4,000		4,500		0	0	
			18,650		28,850	15,500	8,800	20,050
1995	Primary treatment and basic power usage	7,800		9,400				

TABLE H-1

PRELIMINARY POWER NEEDS OF SECONDARY TREATMENT FACILITIES PLAN
(Continued)

Year	Description of power needs	Incremental increase to average load (kw) period	Cumulative average load (kw)	Peak load (kw) period	Cumulative peak load (kw)	Cumulative installed capacity (kw)	Cumulative secure capacity* (kw)	Cumulative shortfall (kw)
	Electrification of five influent pumps, Winthrop terminal pumps and South System flows	4,100		17,700		(3,500)	(2,800)	
	Air emissions control	500		1,250				
	Disinfection (NaOCl purchased)	**		**				
	Construction power	7,000		-12,000				
			24,050		45,200	12,000	6,000	39,200
1999	Secondary facilities and basic power usage	13,500		19,400				

*Secure capacity is that capacity which, because it is provided from two separate sources, is considered to be totally reliable in accordance with EPA criterion as specified in EPA Technical Bulletin EPA-430-99-74-001.

TABLE H-1

PRELIMINARY POWER NEEDS OF SECONDARY TREATMENT FACILITIES PLAN
(Continued)

Year	Description of power needs	Incremental increase to average load (kw) period	Cumulative average load (kw)	Peak load (kw) period	Cumulative peak load (kw)	Cumulative installed capacity (kw)	Cumulative secure capacity* (kw)	Cumulative shortfall (kw)
	Additional air emissions control	250		625				
	Sludge processing	2,000		2,000				
	Disinfection (NaOC1 purchased)	**		**				
	Construction power	3,000		3,000				
			36,800		64,225	12,000	6,000	58,225

*Secure capacity is that capacity which, because it is provided from two separate sources, is considered to be totally reliable in accordance with EPA criterion as specified in EPA Technical Bulletin EPA-430-99-74-001.
** Included in Basic Power.

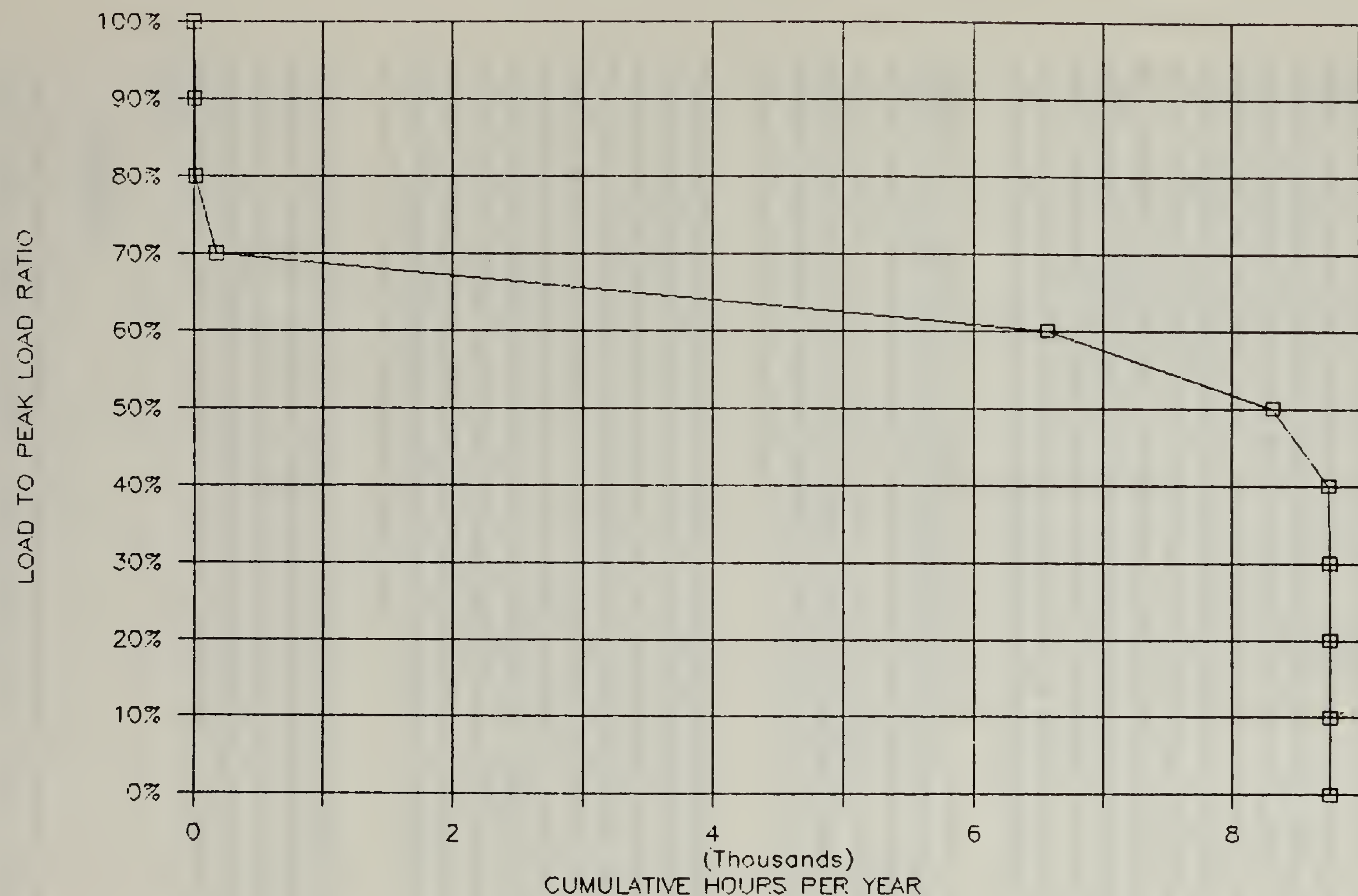

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FIGURE H - 1
LOAD DURATION CURVE

This alternative requires the installation of two trans-harbor submarine cables from independent BECo substations to meet the electrical power redundancy requirements for the project. Cable construction would require environmental reviews and permits. For the purpose of this study, it was assumed that BECo would design, license, and install these cables, while MWRA would construct the on-island substation. In a September 1987 meeting, however, BECo indicated a willingness to consider owning and operating the high-voltage portion of the on-island substation; MWRA would still be responsible for the low-voltage side of the substation and the distribution system. The cost to MWRA for the high-voltage portion would then be reflected in the electric rates plus upfront capital payments for the backup line. It may also be possible to pay for the two cables and the electrical substation with funds from the Construction Grant Program. This should be a subject of future negotiations with BECo; a possible outcome could be a sharing of the initial capital investment and reduced electric rates. Environmentally, increased operation of existing on-site capacity units must be evaluated in terms of potential increases in emissions above the baseline yet to be determined by the Massachusetts Department of Environmental Quality Engineering (DEQE).

Alternative 3: Combined On-site Generation and Off-site Purchase. Purchased power from BECo, and/or on-site power generation capacity, would be dispatched economically to meet 100 percent of Deer Island's power requirements. Unless the on-site power plant has sufficient capacity to meet the 1999 peak shortfall of 58 MW, a second cable power supply with sufficient capacity to operate the entire plant should also be provided as backup to the primary supply. This alternative requires cable connections with BECo similar to those discussed for Alternative 1 and also includes additional on-site capacity.

The impact of these additions of on-site capacity on air quality and noise levels have been evaluated using emissions information currently available. This information includes an estimate of the Deer Island baseline emissions and the predicted future emissions, except for NO_x, based on EPA guideline AP-42 (Compilation of Air Pollution Emission Factors, Volume 1, Stationary Point and Area Sources, 4th Edition, October 1986). Generating units included in this preliminary analysis are provided with commercially available NO_x emissions and noise controls typically provided for such equipment, and some fuel-type limitations are assumed. For example, gas turbines include water or steam injection to reduce NO_x emissions; diesels will burn a maximum 0.3 percent sulfur diesel fuel; and diesels and gas turbines will be enclosed with standard silencing provisions on intakes and exhausts. Specific controls will be evaluated in the detailed engineering and design phase.

AP-42 is useful for study purposes because it is a generic (non-vendor specific) guideline acceptable to regulatory agencies and its use generally results in conservatively high emission predictions. However, a review of manufacturers' data indicates that actual emissions may be significantly lower. Therefore, during detailed design and permitting, a more detailed air quality assessment should be performed using vendor specific data and a baseline approved by the State.

1.4 RESULTS

The off-site power supply evaluated in both alternatives consisted of a primary 115-kv submarine cable supplied from BECo's K Street substation and, as required, a back-up 115-kv

underground and submarine cable brought in through East Boston and Logan Airport and supplied from a BECo substation in Chelsea. When providing off-site power from two separate sources, no on-site generation is required to meet the reliability criterion as specified in EPA Technical Bulletin EPA-430-99-74-001.

For the combined on-site generation and off-site purchase alternative (Alternative 3), combinations of on-site generation capacity with single and dual off-site supplies were developed. The options considered under Alternative 3 were:

- o A single off-site supply, consisting of a 115 kv cable from BECo's K Street substation; plus, a 58 MW combined cycle power plant, consisting of two gas turbines, each with its own supplementary fired heat recovery boiler, and a single condensing steam turbine;

- o Dual off-site supplies consisting of a 115 kv cable from BECo's K Street substation and a 115 kv cable from BECo's Chelsea substation plus a 25.7 MW combined cycle power plant;

- o Dual off-site supplies consisting of the two 115 kv cables from BECo, plus a 15 MW combined cycle power plant.

Each Alternative 3 option is capable of handling critical loads with both the primary off-site source and the largest on-site generating unit out of service. In all cases, credit was taken for existing and committed on-site capacity through its planned service life.

It was determined that, although not required to meet the EPA reliability criteria, additional on-site generating capacity is economically beneficial and provides additional protection against total offsite power failure. In all cases under Alternative 3, sufficient capacity to share the peak load results in the most economical operating conditions. The additional on-site generating capacity of 25.7 MW was found to be the most cost effective alternative based on the estimated load projections and economic assumptions included in this report. Furthermore, the total recommended on-site capacity of 25,700 kw of new capacity plus the 12,000 kw of capacity already committed will provide sufficient power to keep primary treatment in service in the event of a total power failure, such as the 1965 Northeast blackout. Since the 15 MW combined cycle plant option offerred no other benefits, it was dropped from further consideration.

The on-site generating capacity will tie into the electrical substation, as shown on the electrical one-line diagram which is Figure H-2. An arrangement of the 25.7 MW powerhouse and electrical substation is shown on Figures H-3, H-4, H-5, and H-6. The fundamental flow diagram in Figure H-7, is a schematic respresentation of the manner in which power and steam for heating will be generated.

The seasonal heating load, as shown in Table H-2, was calculated to be 52,438 x 10^6 Btu for building heating and 33,697 x 10^6 Btu for tunnel galleries heating, with a heat demand of 15.3 x 10^6 Btu per degree day.

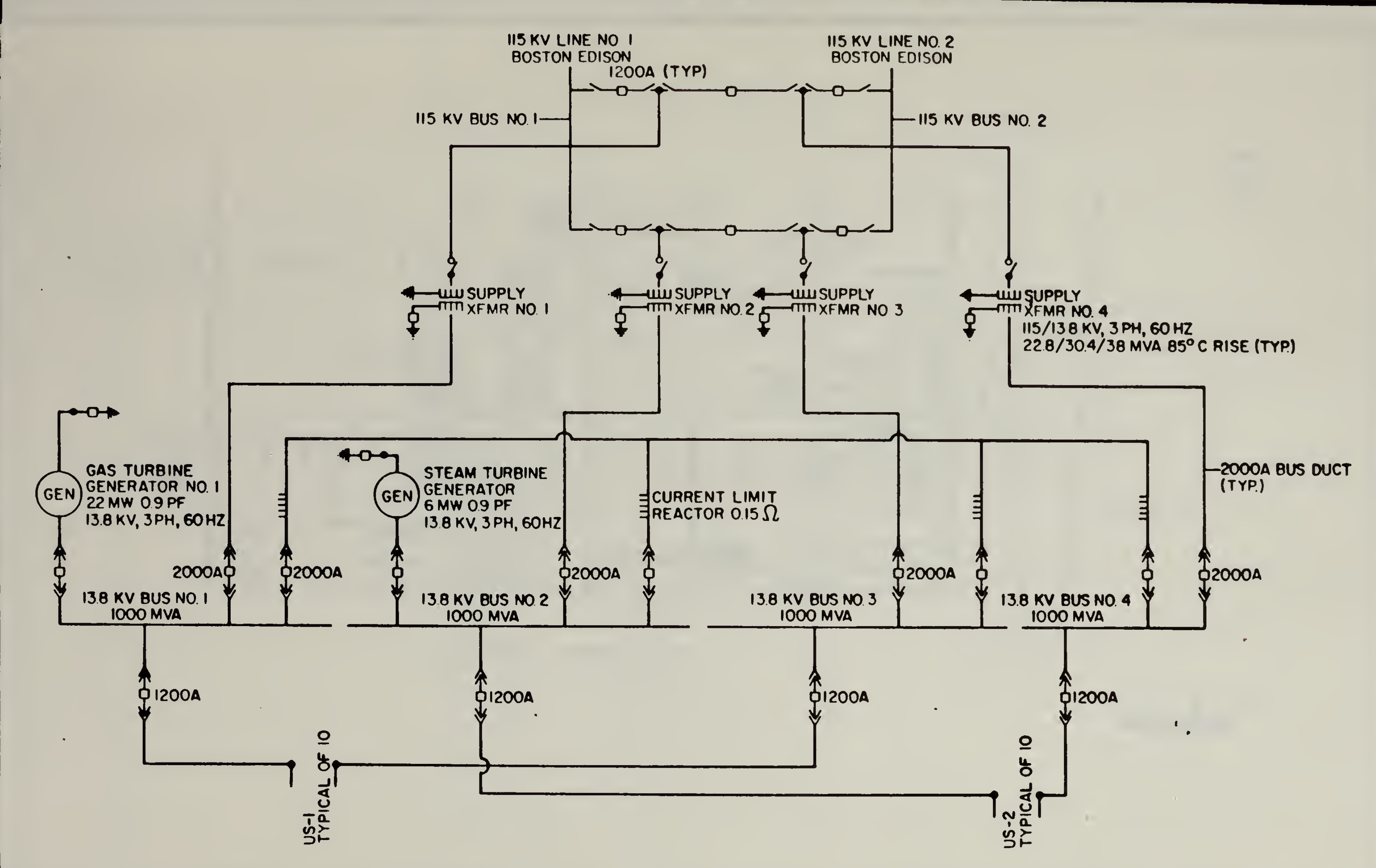

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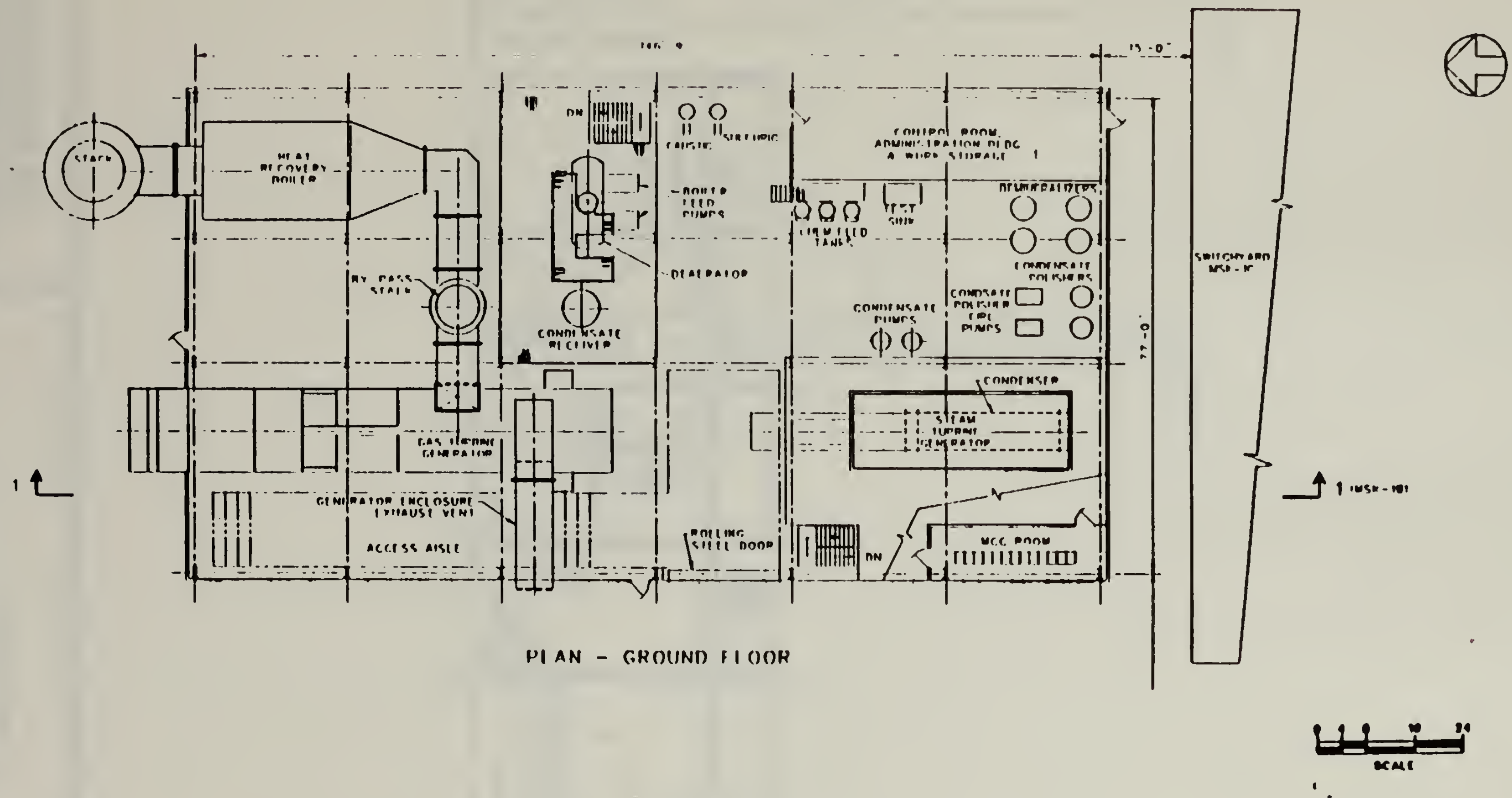
FIGURE H - 2
ELECTRICAL ONE LINE DIAGRAM
POWER SUPPLY



PLAN - GROUND FLOOR

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FIGURE H - 3
POWER HOUSE ARRANGEMENT

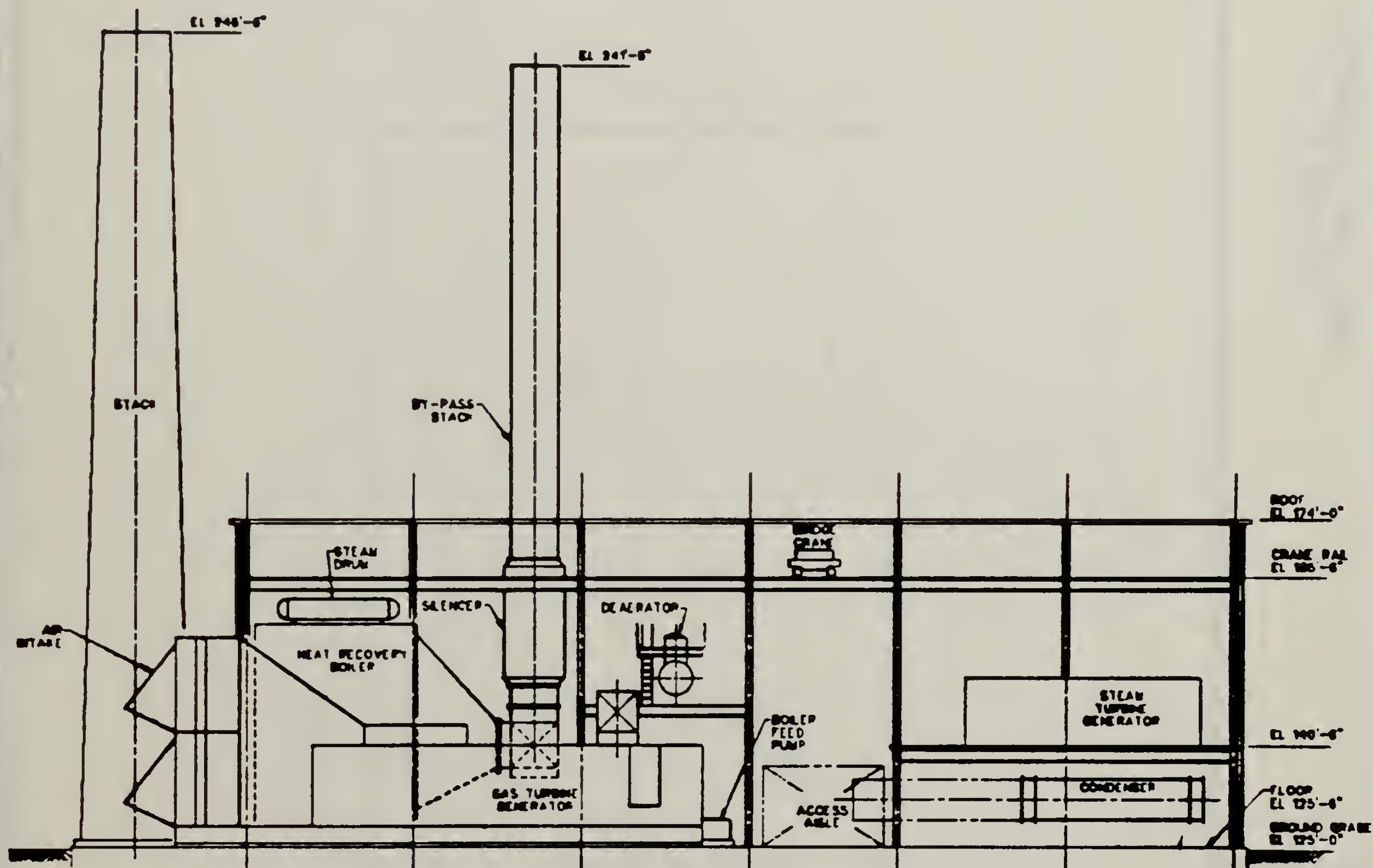

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FIGURE H - 4
POWER HOUSE ELEVATION

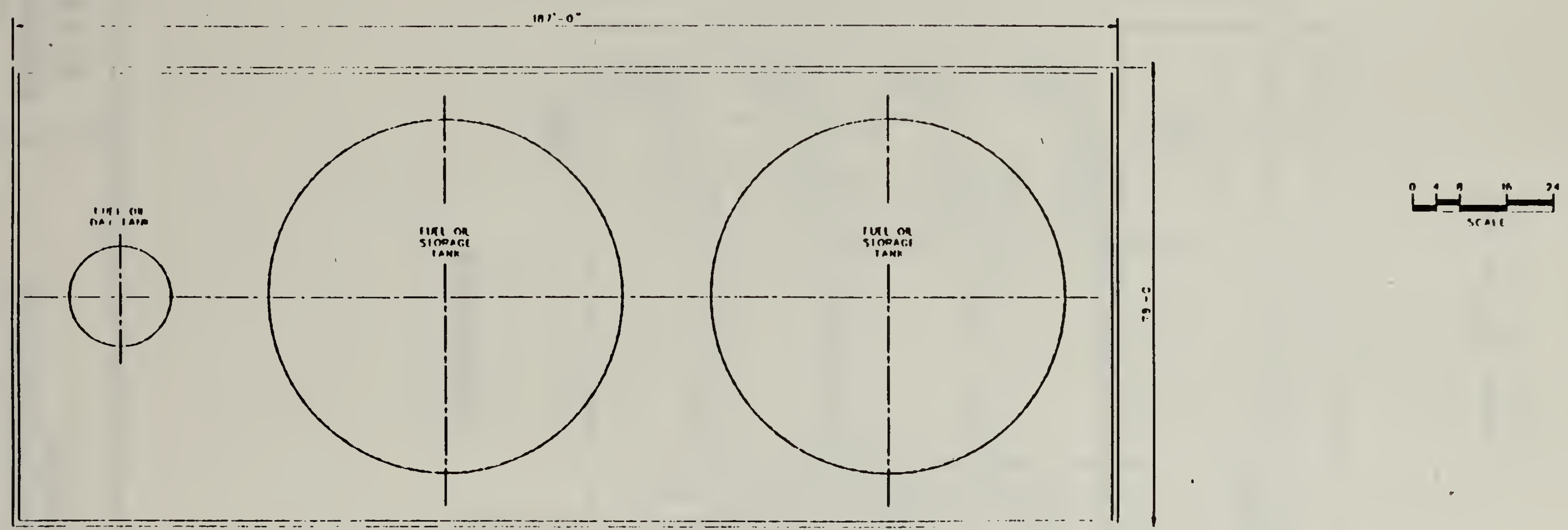

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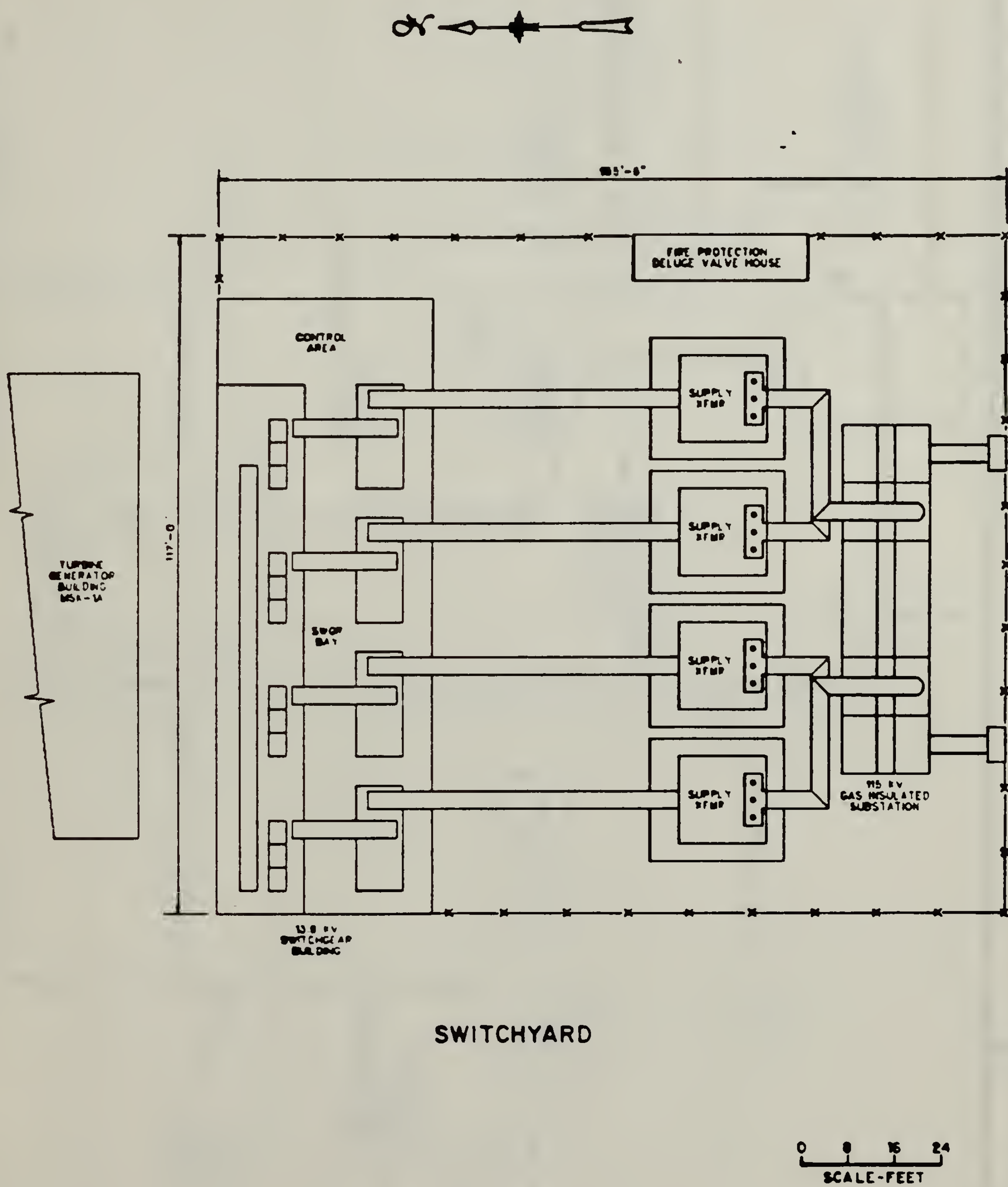
FIGURE H - 5
FUEL OIL STORAGE



MASSACHUSETTS WATER RESOURCES AUTHORITY	FIGURE H - 6 ELECTRICAL SWITCHYARD PLAN

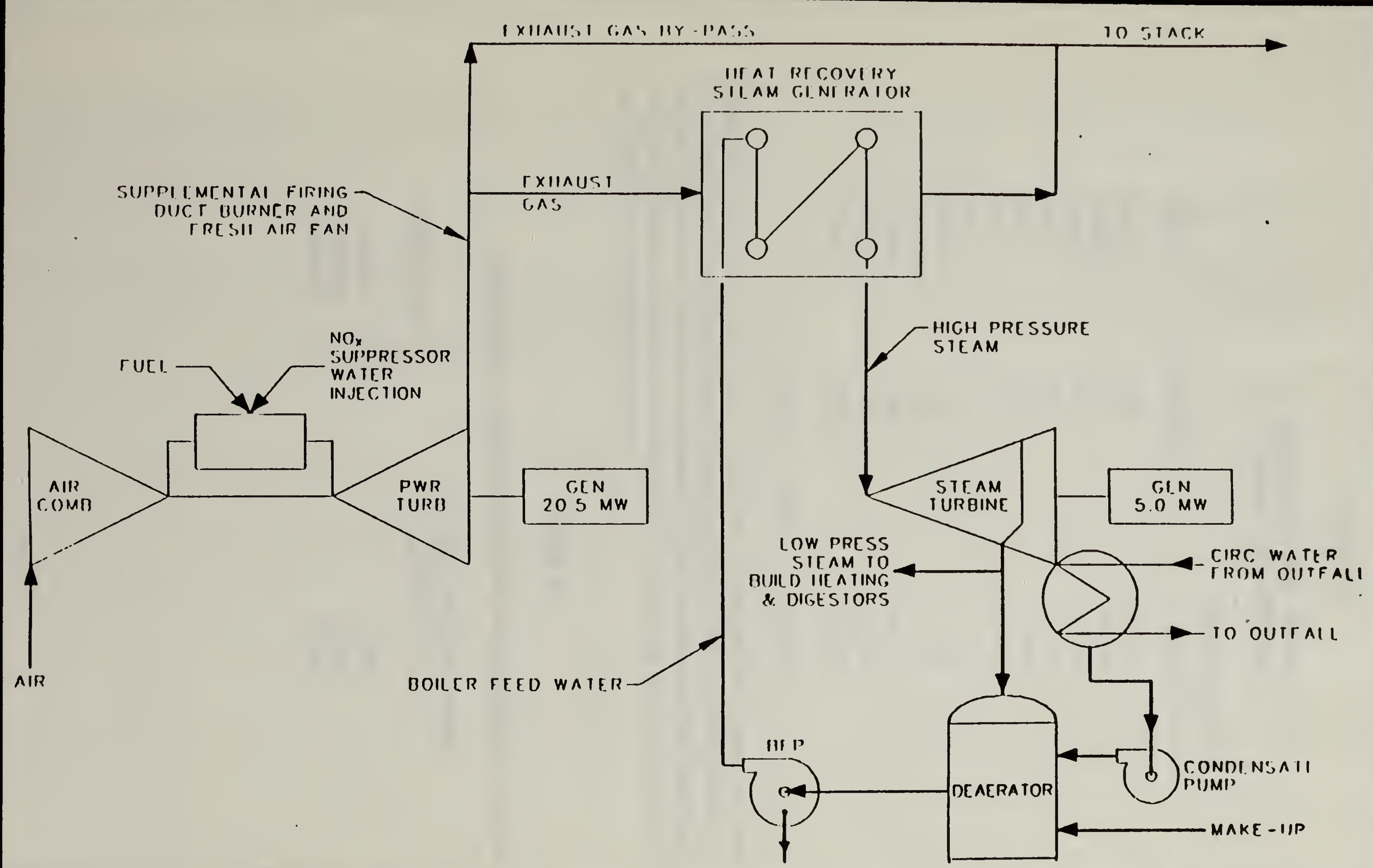


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FIGURE H - 7
FUNDAMENTAL FLOW DIAGRAM

TABLE H-2

HEAT LOAD PER MONTH
BUILDING AND TUNNELS

Month	Degree days		Heat load/month ($Btu \times 10^6$)
January	1088		16,634
February	972		14,860
March	846		12,934
April	513		7,843
May	208		3,180
June	36		550
July	0		0
August	9		138
September	60		917
October	316		4,831
November	603		9,219
December	983		15,029
	5,634	Total	86,135

In addition to the building heating load, a heating load for the anaerobic digesters may also exist. The heating load for the digestion process was calculated for the various levels of treatment, which include fast-track improvements in 1988, the addition of Nut Island flows in 1995, and the addition of secondary treatment in 1999. The average monthly heat loads for these milestones are tabulated in Table H-3.

TABLE H-3

PROJECTED AVERAGE MONTHLY DIGESTER HEAT LOADS

Milestone date	Average monthly heat demand $Btu/10^6$
1988-1994	4,250
1995-1998	11,130
1999-2020	21,000

1.4.1 FUEL

The primary fuel possibilities for the on-site power plant are natural gas and/or No. 2 fuel oil. According to Boston Gas, a new 16-inch-diameter pipeline would have to be constructed from Revere, through Winthrop, to Deer Island. Boston Gas would need to conduct a more detailed study involving gas supply availability and transmission before it could develop a price or commit to sales. Therefore, oil was selected as the primary fuel to use in the economic and environmental analyses of this study. It should be noted that, based on manufacturer's data, air emissions based on oil will generally result in higher emissions than natural gas. Therefore, if natural gas should become an economically viable future alternative, the air quality impacts should be less than those predicted in this report for oil.

The fuel requirements to satisfy required electrical generation and heating demand average 400,000 gal/mo of No. 2 fuel oil. It is currently proposed to deliver fuel by barge. Barges having a capacity of approximately 400,000 gal are available. Barges of this capacity are 165 ft long and 34 ft wide and draw 10 ft when fully loaded. An on-barge unloading capacity of 2,500 gal per hour is available. At this unloading rate seven days would be required to unload the barge. Although the average delivery would be one barge per month, some months may require two deliveries.

Clearly, seven days of unloading time is not acceptable. Therefore, it is proposed that sufficient on-dock unloading capability be provided to reduce the dockside time to 1.7 days. This will entail the provision of an unloading capacity of 10,000 gal/hr. The requirement will be for four 2,500-gal/hr pumps pumping through two 8-in-diameter lines of appropriate material routed in a pipe chase from the dock to the oil storage tanks located adjacent to the existing pumping station.

The fuel storage requirement is for a 30-day reserve storage. This will require two 400,000-gal oil storage tanks in a diked area adjacent to the proposed power plant. These tanks will be 60 ft in diameter by 20 ft high.

The power plant will be totally enclosed in a building 77 ft-0 in. by 146 ft-9 in. by 49 ft-0 in. high, having a stack 121 ft-6 in. high.

1.4.2 ECONOMIC EVALUATIONS

An economic evaluation of the alternatives consisted of comparing the present worth of expenditures for power purchases, fuel purchases, operation, and maintenance of generation capacity, and capital costs for off-site power supplies and new on-site generation capacity over a study period from 1991 to 2020. In each case evaluated, the same electric and building heating loads were met. The evaluations were conducted twice, once with the assumption that digesters would be included in the facility and once with the assumption that they would not.

The digesters require additional heating steam, but they provide a free source of fuel for the committed dual-fuel diesels and/or combined cycle units. Current electric rates and fuel costs were used, without real escalation. A real discount rate of 8.625 percent was used. Results are summarized in Table H-4.

The alternatives evaluated require similar total present worth expenditures, with and without

digesters. A lower capital expenditure is obtained with the dual off-site supply and no new on-site generation, but this alternative has the higher operating cost.

A lower operating expenditure is obtained with the single off-site supply and a large (58 MW) combined-cycle power plant, but this alternative requires the highest capital expenditure. A moderate-size (25.7 MW) combined-cycle unit, in conjunction with two off-site supply lines, yields the lowest present worth expenditure, with or without digesters.

A preliminary review of potential air quality impacts using AP-42 emission factors and noise impacts reveals that these concerns are not likely to constrain the implementation of any of the alternatives evaluated based on current regulatory requirements, recognizing that the combined cycle power plant is essentially a peak shaving plant with an annual load factor of 33 percent or less. As discussed below, based on a review of manufacturers' predicted emissions it also appears feasible to operate a 58 MW combined-cycle power plant with an annual load factor of 100 percent. It is possible that any one alternative may require more mitigation controls than those assumed in the analysis, but at this time it is not expected that any such changes would significantly affect the conclusions of this study. It is necessary, however, to define the required control devices and other mitigation measures required to meet applicable limits.

The preliminary worst case assessment of potential air quality impacts from the peak shaving operation of power generation equipment on Deer Island includes a comparison of estimated future impacts with the impacts of existing operations, as well as an assessment of compliance with currently applicable regulatory requirements and air quality standards. The results of this evaluation indicate that air quality would improve relative to existing conditions for all alternatives for the 1995-2020 period, and that current national ambient air quality standards and other regulatory requirements would be met. As presented in Table H-5, there are either no differences or only small differences in annual pollutant concentrations between the alternatives for the various project phases. The decrease in impacts for the 1993-1995 period for all alternatives is due to the retirement of the Enterprise diesel generators and the remaining Nordberg diesels.

As discussed above, air quality impacts are based on operation of the combined cycle power plant, for Alternative 3A and 3B, as a peak shaving plant. Based on this study, this is the most economical mode of operation. However, it is possible that in the future it may be desirable to operate the on-site power plant more frequently. On a preliminary screening level of analysis, the emissions from the 25.7 MW (Alternative 3B) and the 58 MW (Alternative 3A) combined cycle power plants, assumed to be operating at full load throughout the year, were calculated using two methods. Based on AP-42, which is a conservative non-vendor specific guideline, this base load mode of operation would not be feasible under present regulatory and ambient air quality conditions for either alternative, for either oil or natural gas firing, unless offset requirements associated with the CO and ozone non-attainment status of Deer Island could be satisfied. Based on manufacturers' predicted emissions, however, this base load mode of operation would be feasible for either alternative for either oil or natural gas firing.

Additional air quality modeling will be performed as part of the final Facilities Plan, once the baseline has been established by DEQE. Refined modeling, incorporating five years of meteorological data and manufacturers' emissions data, will be performed for the 1988-1995 time period. The purose of this refined modeling is to determine equipment operating restrictions,

TABLE H-4

ECONOMIC EVALUATION OF ALTERNATIVES

	Alternative 1 Dual off-site supply, no new generation	Alternative 3A Single off-site supply, 58 MW CC *	Alternative 3B Dual off-site supply, 25.7 MW CC
WITH DIGESTERS			
Present worth of capital expenditure ($1000)	20,100	60,823	40,423
Present worth of operation expenditures ($1000)	122,480	92,421	99,194
Total present worth ($1000)	142,580	153,245	139,617
WITHOUT DIGESTERS			
Present worth of capital expenditure ($1000)	20,100	60,823	40,423
Present worth of operation expenditures ($1000)	141,396	111,430	117,922
Total present worth ($1000)	161,496	172,254	158,345

* CC = combined cycle

TABLE H-5

CHANGES IN AIR QUALITY ANNUAL CONCENTRATIONS ($\mu g/m^3$) OF ALTERNATIVES 1, 3A AND 3B COMPARED TO EXISTING IMPACTS

	NO_x	SO_2	TSP
Year	Annual	Annual	Annual
Baseline	0	0	0
1988-1989	-7	-1	-1.8
1990-1994	7	+1	0.3
1995-1998	-14	-2	-1.0
Alternative 3A			
Alternative 3B	-14	-2	-2.0
1999-2020			
Alternative 3A	-14	-2	-2.0
Alternative 3B	-12	-2	-2.0

if any, at Deer Island during this period. For the 1995-2020 time period, a screening level analysis, incorporating the DEQE-approved baseline and emissions predicted by manufacturers, will be performed for the combined-cycle power plant alternatives. The purpose of this screening analysis is to determine if there are any air quality imposed restrictions on the size, annual load factor, or fuel burned for an on-island combined cycle power plant. Refined modeling for the 1995 - 2020 time frame will not be required for the Facilities Plan, unless operating restrictions are indicated by the screening analysis.

During detailed design and permitting, refined modeling incorporating five years of meteorological data and vendor specific emissions data should be performed for the 1995-2020 time period.

1.5 RECOMMENDATIONS

Because the present worth cost differences between the three alternatives (with or without digesters) is within ten percent, it is recommended that some additional on-site capacity be installed to protect against total off-site power failure. Based on the economic results of this study, implementation of Alternative 3B (dual 115 kv off-site power cables from BECo and a 25.7 MW combined cycle on-site power plant) is recommended. The combined cycle power plant should be capable of burning No. 2 fuel oil and natural gas. The MWRA should continue to investigate the availability and cost of an off-island source of natural gas.

Based on these preliminary assessments of power demand growth over time, planned modifications/additions, and retirement of existing equipment, the recommended approach for developing the required reliable power supply to support construction and operation of the Deer Island wastewater treatment plant consists of the following steps. These steps are required, based on increased usage with time and the amount of power deemed to be uninterruptible.

1. Install immediate power supply from MECo's Winthrop grid.

2. Install first 115 kv permanent feeder from BECo's K Street substation.

3. Complete installation of 25.7 MW combined cycle power plant.

4. Install second 115 kv permanent feeder from BECo's Chelsea substation.

It is further recommended that MWRA re-evaluate this study prior to authorizing the installation of the combined cycle power plant and the second 115 kv permanent feeder from Chelsea. The results of this study are based on current economics, estimated load projections, and the ability of BECo to provide long-term reliable power from two separate sources. If, in the future, additional on-site capacity is found to be desirable, an evaluation of air quality and noise impacts should be performed.

1.6 IMPLEMENTATION PLAN

It is recommended that MWRA file with BECo immediately a Power Service Agreement requesting electric service to Deer Island. The request should be for two services from separate sources sized at approximately 70 MW. Having two feeders from separate sources satisfies the EPA requirement for an uninterruptible supply. The request for service should include a request for approximately 15 MW of immediate power to support construction. The request should specify

that the earliest possible in-service date is required to satisfy early site preparation and that a date of no later than 1 January 1990 is acceptable for the immediate power. MWRA should further request that one of the permanent 115-kv cables be installed as soon as possible after the immediate power supply but no later than 1 January 1992.

The request for service must also include a clause that requires BECo to notify MWRA in writing if it cannot have a 115 kv cable in service by 1 January 1992. This notification must include the reasons why this cannot be accomplished and must state the earliest possible in-service date. This written notification must be received before 1 March 1988 in order for MWRA to implement the recommended capacity addition on Deer Island to meet the energy shortfall, using public bidding procedures.

For both immediate and permanent power supply options, MWRA will be required to own and operate the low-voltage side of the substation and its own distribution system; BECo is estimating its capital costs only for the high voltage side of the substation. It is recommended that MWRA bidding of its design work begin in late 1987 so that the construction of its substation will be completed in time for the required in-service dates.

In summary, the recommended approach for developing the required reliable power supply to support construction and operation of the Deer Island wastewater treatment plant consists of the following steps:

1. Install immediate power supply from the MECo Winthrop grid by 1 January 1990 or sooner.

2. Install first 115 kv permanent feeder from K Street by 1 January 1992.

3. Evaluate this study to refine the size of the combined cycle power plant. Complete this step prior to authorizing detailed engineering to support steps 4 and 5 below.

4. Complete installation of combined cycle power plant by 1 January 1995 or sooner.

5. Install second 115 kv permanent feeder from Chelsea by 1 January 1995, if required.

Variations not considered in this study, but recommended for future consideration by MWRA during the final power supply detailed engineering and design are:

1. Retention of a private party with specialized expertise in the operation and maintenance of power- and heat-generating systems to operate and maintain all on-site power- and heat-generating equipment.

2. Third-party ownership of the on-site power and steam production facility utilizing some or all of the digester gas.

3. Negotiate a contract, with favorable rates, for an uninterruptible or interruptible (back-up with oil) off-island supply of natural gas.

2.0 INTRODUCTION

The energy requirements of the Deer Island treatment facilities will greatly increase as the existing facilities are rehabilitated or replaced and new facilities are added for wastewater pumping and treatment. As part of the Massachusetts Water Resource Authority (MWRA) Secondary Treatment Facilities Plan, the power and other energy needs of the facilities were identified, and realistic alternative methods for supplying those needs were evaluated. The methodology used required that electrical power and thermal energy requirements, as well as the amount and energy value of digester gas which may be produced by the facility, be estimated. This analysis was necessary to ensure that energy needs are met throughout the rehabilitation, construction, and operation of the Deer Island treatment facilities.

During the preliminary power supply alternatives study, three options were considered. The first was to purchase all energy, primary supply plus backup, from a local utility. The second was to add sufficient generating capacity to meet the entire requirement with the largest unit out of service and therefore have no connection with the local utility. The third involved purchasing all energy from a single source and adding sufficient generating capacity to supply all required energy should the tie with the utility fail in service.

At the time that the Preliminary Energy Report was discussed with the MWRA Board of Directors, the Board voted to eliminate Alternative 2 (i.e., 100 percent on-island generation of Deer Island power requirements). This alternative was, therefore, deleted from further consideration. It was further decided that meetings would be held with both Boston Edison Company (BECo) and Massachusetts Electric Company to determine which could satisfy both the peak demand and EPA's reliability criterion, which requires power from two separate sources. Deer Island is currently within BECo's licensed service area.

Based on the vote of the MWRA Board and the estimated power demands, the following two basic power supply alternatives for primary and backup power for Deer Island were considered further:

	Primary Power	Backup Power
Alternative 1:	Purchase (BECo)	Purchase (BECo) (i.e., a second cable)
Alternative 3:	Combination of on-site generation/purchase	Combination of on-site generation/purchase

3.0 EXISTING POWER GENERATION FACILITIES

3.1 DEER ISLAND DIESEL GENERATORS

The existing power generating capability at Deer Island consists of five diesel generator sets provided by the Enterprise Engine & Machinery Company of Oakland, CA. The diesels are eight-cylinder, in-line type engines that can be operated on digester gas or diesel fuel. The generators are rated at 700 kw each and were furnished by Allis Chalmers. Although they are still fairly reliable after 18 years of service, rehabilitation is taking place under the Fast-Track Improvement's Program.

The Fast-Track Improvements Program calls for the installation in 1988 of two new 6,000-kw, dual-fuel diesel engine/generator sets to be located in a new building adjacent to the existing power plant. The five existing 700-kw diesels will have been rehabilitated, which will extend the life of these diesel engine generators through 1995.

A new power distribution arrangement in 1988 will allow the diesel generators to operate in parallel or to be separated (five existing diesel generators on one bus and two new diesels on another bus). In general, the two new diesels will power the electric-driven raw wastewater pumps, and the existing diesels will power all other plant loads. Breakers will be provided to allow the waste treatment facility to be powered from either of the two new diesels and the five existing diesels.

The existing once-through engine cooling water system will be replaced with a closed-loop system with heat rejection through cooling towers for all diesel engines. The new system will remove heat from the jacket water of the Enterprise engines, the new 6,000-kw diesel engines, and the remaining Nordberg engines.

Sludge-recirculating pumps, sludge heat exchangers, a steam heat exchanger, and an additional Cleaver Brooks boiler will be added to the plant during the Fast-Track Improvements Program. The heated closed-loop cooling water will be routed through heat exchangers to provide heat to the sludge-heating water, which in turn will be routed through heat exchangers to maintain the anaerobic digesters at the proper temperature. This heat-recovery feature has been accounted for in the calculations for the energy supply alternatives.

The two new 6,000-kw diesel engines will be equipped with hospital-type dry silencers for maximum sound attenuation. Waste heat boilers will not be installed for exhaust gas heat recovery.

3.2 DEER ISLAND DIESEL PUMP DRIVES

The Deer Island Main Pumping Station consists of nine vertical-shaft, mixed-flow, bottom-suction sewage pumps. Each pump is rated for 90 million gallons per day (mgd) at 105 ft total dynamic head (tdh) and 400 rpm. The pumps are driven through 90-ft-long shafts. Eight

pumps are driven by diesel engines, and one pump is driven by a 2,000-hp synchronous electric motor with variable-speed magnetic coupling. The coupling is designed to operate over a 250- to 400-rpm speed range.

The diesels are 12-cylinder, radial-type, vertical-shaft engines furnished by the Nordberg Manufacturing Company of Milwaukee and St. Louis. Because of their demonstrated poor reliability, three Nordberg engine-driven pumps will be retired in 1988 under the Fast-Track Improvements Program, and five will remain in service until 1995. New motor-driven pumps will replace the retired units, and one additional motor-driven pump will be added in the currently empty pump bay.

3.3 WINTHROP TERMINAL DIESEL PUMP DRIVES

The Winthrop terminal headworks contains six vertical-shaft, centrifugal-flow, bottom-suction sewage pumps. Four pumps (1 through 4) are driven by electric motors and two pumps (5 and 6) are driven by diesel engines. The electric motor-driven pumps are rated at 15 mgd at 30 ft tdh. The diesel-driven pumps are rated at 60 mgd at 21 ft tdh.

The diesels are six-cylinder in-line engines as manufactured by Fairbanks/Morse, and drive the pumps through 90-degree offset gear boxes.

The Fast-Track Improvements Program calls for the removal of the diesel drives and all associated equipment. They are to be replaced with variable-speed motor drives as part of the Fast-Track Improvements Program.

4.0 ENERGY PROJECTIONS

4.1 PROJECT MILESTONES

The Massachusetts Water Resource Authority (MWRA) improvement program at the Deer Island treatment plant is a phased program that will initially address the reliability and capability of existing treatment facilities, then will address the improvements necessary to achieve both primary and secondary treatment of wastewater at Deer Island. Table H-6 lists the sequence of phases that have the greatest near future impact on power needs.

The Fast-Track-Improvements Program for Deer Island addresses the reliability of the existing facility. Included in the fast-track program is the partial electrification of the influent pumping station. This modification includes the installation of four new electric motor-driven pumps (1,500 kw) capable of pumping 90 mgd of influent. Operation of these pumps requires expanding the electric generation capacity to handle a load of 6,000 kw (4 x 1500 kw/pump). To provide reliability, two 6,000-kw diesel generators (one a standby unit) are scheduled for installation in 1988 along with the new electric motor-driven pumps. Sufficient capacity exists when the Enterprise diesel generators are combined with one new 6,000-kw diesel generator to run five electric-driven pumps.

In addition, two diesel-driven pumps at the Winthrop terminal headworks will be replaced by two new motor-driven pumps (200 kw each). The remainder of the fast-track program involves improvements to and replacement of equipment to permit the Deer Island facility to treat up to the design capacity.

The new primary treatment facilities to be completed in 1995 will have the expanded capacity to treat both the Deer Island and the Nut Island flows. This expansion also includes finalization of the influent and Winthrop terminal pump electrification and new disinfection facilities.

Secondary treatment is scheduled for completion in 1999.

4.2 IMMEDIATE ELECTRIC POWER DEMAND

The immediate power demand consists primarily of construction-related usages which begin prior to construction of the Deer Island permanent power facilities. Tables H-7 and H-8, which identify average and peak power requirements and essential power, respectively, reflect the requirements for operating the treatment facility while constructing two submarine tunnels, one for the South System influent from Nut Island and the other for the Deer Island effluent outfall. The evaluations of the inter-island transport system and the Deer Island effluent outfall are contained in Volumes IV and V, respectively, of the Secondary Treatment Facilities Plan.

TABLE H-6

IMPACT OF PHASES ON POWER NEEDS

Program phase	Function	Scheduled completion
Add two 6000kw diesel generators.* Add electric motor driven pumps at Deer Island and at Winthrop terminal.*	Reliability improvement to existing facility	1988
Remainder of fast-track improvements	Reliability improvement to existing facility	1991
New primary treatment, influent pump electrification, new disinfection, and addition of South System flow	New primary treatment facilities	1995
Provide secondary treatment	Incorporation of secondary treatment facilities	1999

* Already committed under Fast-Track-Improvements Program

TABLE H-7

PRELIMINARY POWER NEEDS OF SECONDARY TREATMENT FACILITIES PLAN TOTAL NEEDS

Year	Description of power needs	Incremental increase to average load (kw) period	Cumulative average load (kw)	Peak load (kw) period	Cumulative peak load (kw)	Cumulative installed capacity (kw)	Cumulative secure capacity* (kw)	Cumulative shortfall (kw)
1986	One electrified influent pump	1,500		1,500		3,500	2,800	
1986	Basic power usage	650	—	650	—	—	—	—
			2,150		2,150	3,500	2,800	0
1988	Electrification of four influent pumps (additional) and Winthrop terminal pumps	2,500	4,650	7,200	9,350	12,000 15,500	6,000 8,800	550
1990	Construction power	10,000	14,650	15,000	24,350	0 15,500	0 8,800	15,550
1991	Primary sludge-dewatering, piers and basic power	4,000	18,650	4,500	28,850	0 15,500	0 8,800	20,050

TABLE H-7
(Continued)

Year	Description of power needs	Incremental increase to average load (kw) period	Cumulative average load (kw)	Peak load (kw) period	Cumulative peak load (kw)	Cumulative installed capacity (kw)	Cumulative secure capacity* (kw)	Cumulative shortfall (kw)
1995	Primary treatment and basic power usage	7,800		9,400				
	Electrification of five influent pumps, Winthrop terminal pumps and South System flows	4,100		17,700		(3,500)	(2,800)	
	Air emissions control	500		1,250				
	Disinfection (NaOCl purchased)	**		**				
	Construction power	7,000		-12,000				
			24,050		45,200	12,000	6,000	39,200
1999	Secondary facilities and basic power usage	13,500		19,400				

TABLE H-7 (Continued)

Year	Description of power needs	Incremental increase to average load (kw) period	Cumulative average load (kw)	Peak load (kw) period	Cumulative peak load (kw)	Cumulative installed capacity (kw)	Cumulative secure capacity* (kw)	Cumulative shortfall (kw)
	Additional air emissions control	250		625				
	Sludge processing	2,000		2,000				
	Disinfection (NaOCl purchased)	**		**				
	Construction power	3,000		3,000				
			36,800		64,225	12,000	6,000	58,225

*Secure capacity is that capacity which, because it is provided from two separate sources, is considered to be totally reliable in accordance with EPA criterion as specified in EPA Technical Bulletin EPA-430-99-74-001.

** Included in Basic Power.

TABLE H-8

STFP PRELIMINARY POWER NEEDS: ESSENTIAL POWER*
TOTAL NEEDS

Year	Description of power needs	Essential average kw load period	Cumulative essential average kw load	Essential peak kw load period	Cumulative essential peak kw load	Cumulative installed capacity (kw)	Cumulative secure capacity** (kw)	Cumulative essential shortfall (kw)
1986	One electrified influent pump	1,500		1,500		3,500	2,800	
1986	Basic power usage	650	—	650	—	—	—	—
			2,150		2,150	3,500	2,800	0
1988	Electrification of four influent pumps (additional) and Winthrop terminal pumps	2,500	—	6,400	—	12,000	6.000	—
			4,650		8,550	15,500	8,800	0
1990	Construction power	10,000	—	15,000	—	0	0	—
			14,650		23,550	15,500	8,800	14,750
1991	Primary sludge-dewatering, piers and basic power	1,000	—	1,500	—	0	0	—
			15,650		25,050	15,500	8,800	16,250

*Essential power is that power required to operate those plant operations which, if interrupted, would result in unacceptable discharges and/or could present danger to personnel health and safety.

**Secure capacity is that capacity which, because it is provided from two separate sources, is considered to be totally reliable in accordance with EPA criterion as specified in EPA Technical Bulletin EPA-430-99-74-001.

TABLE H-8

STFP PRELIMINARY POWER NEEDS: ESSENTIAL POWER*
TOTAL NEEDS
(Continued)

Year	Description of power needs	Essential average kw load period	Cumulative essential average kw load	Essential peak kw load period	Cumulative essential peak kw load	Cumulative installed capacity (kw)	Cumulative secure capacity** (kw)	Cumulative essential shortfall (kw)
1995	Primary treatment and basic power usage	7,800		9,400				
	Electrification of five influent pumps, Winthrop terminal pumps and South System flows	4,100		17,700		(3,500)	(2,800)	
	Air emissions control	500		1,250				
	Disinfection (NaOCl purchased)	0		0				
	Construction power	-7,000		-12,000				
			21,050		41,400	12,000	6,000	35,400

*Essential power is that power required to operate those plant operations which, if interrupted, would result in unacceptable discharges and/or could present danger to personnel health and safety.

**Secure capacity is that capacity which, because it is provided from two separate sources. is considered to be totally reliable in accordance with EPA criterion as specified in EPA Technical Bulletin EPA-430-99-74-001.

TABLE H-8

STFP PRELIMINARY POWER NEEDS: ESSENTIAL POWER*
TOTAL NEEDS
(Continued)

Year	Description of power needs	Essential average kw load period	Cumulative essential average kw load	Essential peak kw load period	Cumulative essential peak kw load	Cumulative installed capacity (kw)	Cumulative secure capacity** (kw)	Cumulative essential shortfall (kw)
1999	Secondary facilities and basic power usage	6,000		6,000				
	Additional air emissions control	250		625				
	Sludge processing	0		0				
	Disinfection (NaOC1 purchased)	***		***				
	Construction power	3,000		3,000				
			36,800		64,225	12,000	6,000	39,025

*Essential power is that power required to operate those plant operations which, if interrupted, would result in unacceptable discharges and/or could present danger to personnel health and safety.

**Secure capacity is that capacity which, because it is provided from two separate sources, is considered to be totally reliable in accordance with EPA criterion as specified in EPA Technical Bulletin EPA-430-99-74-001.

***Included in Basic Power.

The construction power required by the machines used to bore the tunnels averages 7,000 kw for the larger outfall tunnel that will carry the Deer Island effluent, and 5,000 kw for the smaller inter-island transport tunnel that will carry the South System flow from Nut Island to Deer Island. An additional 3,000 kw of construction power is assumed for miscellaneous construction equipment and facilities.

The average construction power demand (10,000 kw) does not allow for the two tunnels to be constructed simultaneously. The peak construction power demand (15,000 kw) accounts for the eventuality that they will be constructed simultaneously.

When the tunnel construction is completed in 1995, the associated construction power requirement will be eliminated. The remaining 3,000 kw of construction power will support continuing construction of the secondary wastewater treatment and power generation facilities scheduled to be completed in 1999.

4.3 PERMANENT ELECTRIC POWER DEMAND

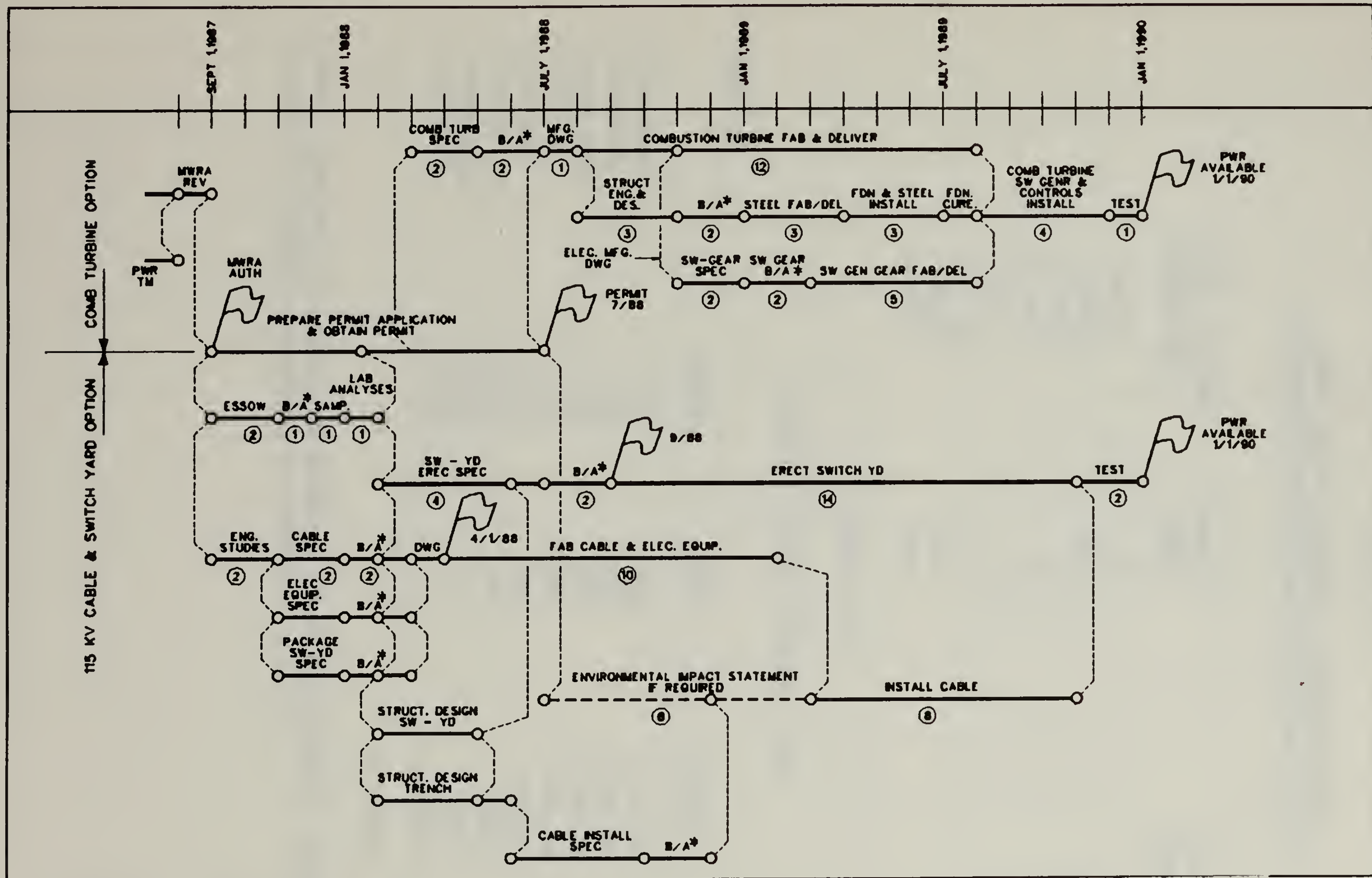
The expanded treatment facilities at the Deer Island wastewater treatment plant will require increased power. The increase in energy requirements will take place in a stepped fashion as the quantity of wastewater treated is increased, and the degree of treatment improves.

The preliminary electric power requirements were tabulated by calculating the equivalent electric power requirements for 1986 and adding the stepped increases for the various uses identified by the process engineers, as discussed in Volume III of the Deer Island Secondary Treatment Facilities Plan. Tables H-7 and H-8 respectively, list electrical power requirements for total power and essential power only,.

The total electric power requirements for the MWRA Deer Island wastewater treatment facility will increase from an average load of 4.65 MW in 1988 to an average load of 36.80 MW and a peak load of 64.22 MW in 1999.

To determine the required electrical and equivalent electrical loads for the facility, a load-duration curve was developed (see Figure H-8). The load duration curve was based on data obtained from the MWRA regarding the number of pumps in service and the appropriate numbers of hours of operation per year for the various combinations of pumps. Those data are presented in Tables H-9 and H-10 along with a tabulation of annual power requirements based on current pumping needs. This was done in order to determine the most economic mix of purchased plus self-generated power.

These electric demand data were presented to BECo in a letter dated 19 May 1987. The data were further discussed at a meeting on 5 June 1987 to solicit BECo's assistance in determining capital, energy, and capacity charges for providing all the electric power that will be required by MWRA's Deer Island secondary wastewater treatment plant. These data were similar to those provided to BECo on a preliminary basis in 1986.



MASSACHUSETTS
WATER RESOURCES
AUTHORITY

FIGURE H - 8
SCHEDULE TO DELIVER 115 - k V SERVICE

TABLE H-9

DEER ISLAND CURRENT SERVICE PUMP DURATIONS FOR BASE LOAD DURATION CURVE

Number of pumps/ capacity (mgd)	Percentage of time	Annual hours of operation
Two/180	100	8760
Three/270	99.9	8750
Four/360	95	8320
Five/450	75	6570
Six/540	2	170
Seven/630	0.1	10
Eight/720	0.05	5
Nine/810	0.01	1

TABLE H-10

YEARLY kw HOUR DEMAND, 1986

Incremental	Load kw	hr/yr	kwh/hr
Minimum load*	4.500	8,760	39,420,000
+ third pump	1,500	8,750	13,125,000
+ fourth pump	1,500	8,320	12,480,000
+ fifth pump	1,500	6,570	9,855,000
+ sixth pump	1,500	170	255.000
+ seventh pump	1,500	10	15.000
+ eighth pump	1,500	5	7,500
+ ninth pump	1,500	1	1,500
Total			75,159,000

*Minimum load equals two influent pumps (3,000 kw) + house load (1,500 kw). The house load was determined from an actual measurement taken at the Deer Island facility.

4.4 HEATING DEMAND

The heating demand at the MWRA Deer Island wastewater treatment plant will increase as new facilities are constructed to provide improved wastewater treatment for increased volumes of wastewater. The heating load varies annually in accordance with the number of degree days/month. The average was varied in a stepped fashion to accommodate increases in flows and implementation of secondary treatment.

Total seasonal heating loads were determined by using published data that give seasonal steam demand per degree day per 1,000 ft^3 to be heated for the various types of buildings. This reflects hours per day of occupancy and required comfort levels. A value of 1,000 Btu/lb of useful heat is assigned to a pound of steam. For the buildings, a value of 0.962 lb steam/degree day/1,000 ft^3 was used. For the tunnel galleries, a value of 0.202 lb steam/degree day/1,000 ft^3 was used. This preliminary heating load estimate was based on an ultimate building volume of approximately 8,000,000 ft^3 and tunnel gallery volume of approximately 9,000,000 ft^3.

The number of degree days per month and the total degree days per heating season for Boston were obtained from the 1981 edition of the ASHRAE Fundamentals Handbook. They are shown in Table H-11, which also shows expected monthly heat loads.

In addition to the building heating load, a heating load for the anaerobic digesters may also exist. The heating load for the digestion process was calculated for the various levels of treatment, which include fast-track improvements in 1988, the addition of Nut Island flows in 1995, and the addition of secondary treatment in 1999. The average monthly heat loads for these milestones are tabulated in Table H-12.

4.5 DIGESTER GAS PRODUCTION

The anaerobic digestion process produces digester gas as a product while significantly reducing the weight of sludge requiring disposal. The digester gas produced consists primarily of methane, some carbon dioxide, and hydrogen sulfide. The heating value of the gas is estimated to be 600 to 650 Btu/scf. The amount of gas produced depends on the amount of volatile solids removed from the influent and the digester reduction efficiency.

The digester gas production was calculated for the various stepped improvements in treatment from 1988 to 1999 and is presented in Table H-13. The economics of using digester gas, if available, are discussed in Chapter 6.0.

TABLE H-11

HEAT LOAD PER MONTH
BUILDING AND TUNNELS

Month	Degree days	Heat load/month ($Btu \times 10^6$)
January	1088	16,634
February	972	14,860
March	846	12,934
April	513	7,843
May	208	3,180
June	36	550
July	0	0
August	9	138
September	60	917
October	316	4,831
November	603	9,219
December	983	15,029
TOTAL	5634	86,135

The seasonal heating load was calculated to be $52,438 \times 10^6$ Btu for building heating and $33,697 \times 10^6$ Btu for tunnel galleries. This results in a total seasonal heating load of $86,135 \times 10^6$ Btu and a heat demand of 15.3×10^6 Btu per degree day.

TABLE H-12

PROJECTED AVERAGE MONTHLY DIGESTER HEAT LOADS

Milestone date	Average monthly heat demand $Btu/10^6$
1988-1994	4,250
1995-1998	11,130
1999-2020	21,000

TABLE H-13

DIGESTER GAS PARAMETERS*

	Period 1986 to 1994	1995 to 1998	1999 to 2020
Sludge production (dry tons/day)			
Primary sludge production	58	163	177
Secondary sludge production	0	0	113
Total sludge production (solids)	58	163	290
Gas production			
Total Gas, Mcf/day	0.744	2.01	3.84
MBtu/day	446	1,254	2,304
MBtu/hr	18.6	52.26	96

The amount of digester gas produced is based on data provided by Black & Veatch in conjunction with Camp Dresser & McKee.

5.0 ALTERNATIVE 1: OFF-SITE PURCHASE OF ALL REQUIRED ADDITIONAL ENERGY

Alternative 1 consists of purchasing all the additional electric power required for the Deer Island treatment facility from Boston Edision Company (BECo). Because of the load size, BECo proposes to bring electric power to Deer Island at 115 kv, terminating at an on-island 115-kv switch yard. No additional on-site generating capacity beyond the two committed 6 MW dual fuel diesels is proposed.

5.1 RELIABILITY CONSIDERATIONS

Based on EPA regulations, a major portion of the electric power required at Deer Island falls into the critical service category and is therefore uninterruptible or essential as identified in Tables H-7 and H-8 respectively. BECo was informed of this requirement in a meeting on June 5, 1987. BECo responded that the requirement could be satisfied by bringing 115-kv cables capable of delivering 70 MW of power (normal supply) from the K street substation to Deer Island (submarine) and from BECo's station #488, Chelsea, to Deer Island via East Boston and across Logan Airport (buried and submarine). With these two cables in place from separate sources, the EPA reliability criterion is satisfied.

5.2 SCHEDULE TO PROVIDE ELECTRIC SERVICE

BECo has stated that with authorization as early as September 1987 they would envision a schedule for delivering the 115-kv electric service to Deer Island extending to mid-1991. The major activities that make up the project effort are the permitting activities and the engineering, fabrication, and construction of the cable trenches, cable and the switchyard. BECo's schedule is driven by the work load to which their staff is currently committed.

BECo did state in a meeting on June 5, 1987 that if certain activities could be performed by others, it might be possible to meet a required in-service date of January 1, 1990 to support construction of underharbor tunnels.

A schedule has been developed (Figure H-8) that, if adhered to, would permit BECo to deliver the 115-kv electric service from BECo's K Street substation by January 1, 1990. This schedule is contingent on completion of the permitting activities in ten months, which should be achievable. In addition, this schedule requires a commitment by BECo to perform engineering, procurement, and some fabrication simultaneously with the permitting activities and prior to permit receipt.

BECo has since negotiated with Massachusetts Electric Company (MECo) to supply the required 15 Mw of construction power. This source of supply will remain in service until the permanent power supplies are in place. The power will be delivered to BECo at 24 kv at the Winthrop/Boston line. MECo has assured BECo that meeting the required in-service date of January 1, 1990 is easily achievable since only 18 months is required to complete the

installation. It is estimated that the cost for this service could be approximately $2.5 million dollars. If this service could be routed in the same trench as the proposed new water main, savings of approximately $500,000 could be achieved.

This supply will be delivered via an underground transmission line originating from a substation in Winthrop. It is currently proposed that this service will terminate at a 24-kv to 13.8-kv temporary transformer owned by BECo to be located at the Boston/Winthrop line at the Deer Island peninsula. From that point, MWRA will be responsible for running a 13.8-kv line to the wastewater treatment plant's substation. MWRA is also expected to be responsible for the distribution system required to deliver the construction power where it is needed. It may be possible for MWRA to negotiate a contact for BECo to perform this work.

5.3 CAPITAL COST FOR PROVIDING ELECTRIC SERVICE

The costs for the various permanent power supply routes to Deer Island are outlined as follows (for all cost estimates, the most direct routes are assumed; for the trenching estimates, it is assumed that no serious problems will be encountered, such as ledge or bedrock):

1. Submarine cables from K Street to Deer Island

   Distance: 20,500 ft

   Construction: Four 400-KCmil copper single-phase submarine cables ($32/ft) in one trench (10 ft deep in ship channels and 5 ft deep in other areas)

   Cost in 1987 dollars: $8,900,000

   Cost of one 115-kv circuit breaker at K Street: $225,000

2. Buried and submarine cables from station #448, Chelsea to Deer Island via East Boston and across Logan Airport

   Distance: 10,500 ft

   Construction: Four 400-KCmil copper single-phase buried and submarine cables for entire length in one trench

   Cost in 1987 dollars: $10,000,000

   Cost for one 115-kv circuit breaker at station #448: $225,000

3. <u>Two separate submarine cables from K Street to Deer Island with eight single-phase cables in one trench (no service from Chelsea)</u>

   Cost in 1987 dollars: $12,500,000

   Cost of two 115-kv circuit breakers at K Street: $450,000

   Extra cost for two trenches: $2,750,000

Note: Option 3 does not comply with the EPA requirement of having two separate sources of supply in order to be considered uninterruptible. For that reason, it should not be considered further.

BECo's policies which will affect their evaluation of the preceding costs are:

1. BECo will provide one source of supply in the public way at BECo expense, not to exceed 1.5 times the annual estimated revenue. An executed agreement between MWRA and BECo to that effect would be required.

2. Said agreement would also require payment for all additional work over the normal supply. Normal supply is four 400-KCmil copper single-phase cables in a single trench from the K Street substation. The capital costs would be:

$8,900,000	for cable trenching
225,000	for circuit breaker at K street
$9,125,000	total

BECo would, thus, require a $6,085,000 annual revenue to support this $9 million investment. If this return is not achievable, that portion of the capital cost that could not be recovered in 18 months would be passed on to MWRA.

5.4 OPERATING AND MAINTENANCE COST OF SERVICE

Based on BECo's requirements for capital investment, the annual revenue of $6,085,000 to support its capital investment in a 115-kv cable from K Street will not be achieved until 1995. Therefore, negotiations with BECo will be required to determine if an in-service date prior to 1995 for this 115-kv cable will result in additional capital charges to MWRA.

The operating costs associated with the off-site supply alternative consist of the base cost of electricity, the demand charge, fuel adjustment, and any facilities charges that must be passed on to MWRA. These charges are 3.58¢/kwh average energy charge, including fuel adjustment, $117/kw-yr demand charge and $36/kw-yr of additional facilities charges. These result in payments to BECo averaging $14,868,000/yr in the period 1995 to 1999 and $22,672,000/yr after 1999.

When performing the economic evaluation of this alternative, the capital costs of approximately $4,500,000 for construction of the MWRA-owned substation and maintenance costs were not included since the substation is common to all supply alternatives.

6.0 ALTERNATIVE 3: COMBINED ON-SITE GENERATION AND OFF-SITE PURCHASE

Alternative 3 consists of purchasing primary electric power from BECo and providing electric power from additional on-site generation. Primary electric power can be delivered to Deer Island either by submarine cable from K Street or by buried and submarine cable from Chelsea via East Boston and across Logan Airport, as discussed in Section 5.0. Primary electric power would be delivered at 115 kv to the MWRA-owned switchyard.

For the single cable off-site supply option, backup electric power would be self-generated by a combined-cycle plant, capable of generating up to 58 MW plus two 6-MW diesel generators, for a total capacity of 70 MW. The combined-cycle plant would consist of two combustion turbine-generators (rated at 20 MW each when ambient temperature is 88° F conditions) exhausting to two heat-recovery steam generators (HRSG), which, combined, produce sufficient steam to generate 18 MW in a single steam turbine-generator. The HRSGs would be supplementary-fired to utilize the complete combustion capacity of the exhaust gas.

An auxiliary boiler would provide backup to meet essential power demand in case one of the two trains that make up the combined-cycle plant is not operable to back up the primary electric power supply from BECo. The auxiliary boiler would produce sufficient steam to generate an additional 10 MW in the steam turbine-generator. The auxiliary boiler would also be capable of supplying full steam requirements for heating demand.

The potential on-site generating capacity is tabulated in Table H-14. It shows the methodology of the power generation facilities to meet both peak power demand and essential power demand, assuming the unavailability of any single power generating component.

6.1 RELIABILITY CONSIDERATIONS

The EPA requires two independent sources of electric power at full capacity to ensure reliability of operation of waste treatment facilities. To satisfy this requirement, the on-site power generation facilities, comprised of the 58-MW combined-cycle power plant, the auxiliary boiler, and the two diesel generators, would provide 100-percent backup capability to the primary power supply from BECo. In addition, the on-site power generation facilities would be capable of supplying essential peak electric power demand (as shown in Table H-8) in case the largest component of the power generation facility is out of service coincident with an interruption of primary service from BECo.

Additional reliability is provided through the design process by specifying high quality equipment from experienced and prequalified suppliers and by providing redundancy of equipment where justified.

6.2 ECONOMIC SELF-GENERATION CAPACITY

The digester gas produced in the waste treatment process can be used as fuel in the combustion turbines. The electricity generated can be used to shave the quantity of purchased electricity

TABLE H-14

ON-SITE GENERATING CAPACITY

	Capacity (kW)		
	Each	All Facilities Available	Single Largest Component Unavailable*
Combustion turbine-generators (2)	20,000	40,000	20,000
Steam turbine generators (2)			
Steam from HRSG (2)	9,000	18,000	9,000
Steam from auxiliary boiler	10,000	**	10,000
Diesel generators (2)	6,000	12,000	12,000
Total		70,000**	51,000

* Unavailability of a single component (e.g., the combustion turbine/generator or HRSG) would result in isolation of one train of the combined cycle plant.

** Normal operation to satisfy peak demand would not require the auxiliary boiler, which is provided as backup.

during peak price periods, which are 10^6 hours per day Monday through Friday.

Since digester gas is produced continuously, it would have to be stored during off-peak hours for consumption during peak hours. A storage capacity of 16 hours is sufficient. It is assumed that digester gas would be burned as produced on weekends, since weekends are offpeak hours.

Digester gas production increases to 2,304 x 10^6 Btu/day in 1999 (see Table H-13). Consumption of this gas during the 10-hour peak period results in 230 x 10^6 Btu/hr. The combustion turbines can generate approximately 27 MW burning the digester gas, which translates into a daily reduction in electricity purchase of 270,000 kw-hr.

Burning digester gas represents the most economical self-generation capacity, because if the gas is available it has no cost. Related costs do apply, however, including cost of equipment required to store and transfer the gas, cost of operating personnel, and maintenance costs.

6.3 CAPITAL COST OF CAPACITY

The preliminary capital cost estimate of the on-site generation facilities is based on vendor quotes for a combined-cycle plant and an interconnected auxiliary boiler. These costs are presented in Table H-15. The diesel generators will be added as part of the Fast-Track Improvements Program and are not included in the cost estimate.

The cost estimate assumes a combustion turbine as the basis for sizing and selecting components for the combined-cycle plant.

Budgetary prices were solicited from Stewart & Stevenson Services, Inc., and Solar Turbines, Inc. The capital cost estimate is based on this input combined with Stone & Webster's in-house cost-estimating data and experience.

An option evaluated under the partial self-generation alternative was a reduced-size combined-cycle plant plus two off-site feeders. This plant was sized to provide the most cost-effective mix of off-site purchase and self-generated power.

Combined-cycle plants having a capacity of 25,700 kw and 15,000 kw were considered. Budgetary prices were obtained from the vendors who had supplied pricing for the 58,000 kw plant. These capital cost estimates are also presented in Table H-15. It was determined that a combined-cycle unit having a capacity of 25,700 kw at ambient temperature conditions of 88°F is the most economical choice.

6.4 OPERATING AND MAINTENANCE COST OF CAPACITY

The operating and maintenance cost for the on-site generation facilities comprises variable costs for fuel, maintenance equipment, spare parts, and fixed costs for operating and maintenance personnel.

TABLE H-15

PRELIMINARY CAPITAL COST ESTIMATE
FOR ON-SITE GENERATING CAPACITY

	58 MW ($\$ \times 10^6$)	25.7 MW ($\$ \times 10^6$)	15 MW ($\$ \times 10^6$)
Plant direct costs (including auxiliaries, foundations, buildings)			
Combustion turbine-generators	18.7	8.2	5.1
Heat recovery steam generators	6.3	3.0	1.4
Steam turbine-generator	7.8	3.0	1.4
Heat rejection system	1.0	0.5	0.6
Auxiliary boiler	0.5		
Miscellaneous	1.7	0.8	0.7
Subtotal direct costs	36.0	15.5	9.2
Indirect costs (including contingencies, allowance for funds used during construction, engineering, and construction management)	18.0	7.8	4.6
Total installed cost, 1987 Dollars	54.0	23.3	13.8

The price of distillate fuel used as the basis for the economic evaluation in Chapter 7.0 is $3.75/10^6 Btu, or 52¢ per gallon. The actual fuel price at the time of operation, of course, will vary with market conditions. Based on the price, the fuel cost for the combined-cycle plant would be $0.035/kwh of generation. The most economic dispatching scenario for the on-site generating capacity will determine the annual fuel cost. This is discussed in Section 7.0.

The remaining operating and maintenance costs, excluding fuel, can be estimated at $40/kw-yr for these sizes of combined-cycle plants. This results in an annual cost of $2,500,000 and $1,030,000, respectively, which is used as part of the economic evaluation in Section 7.0.

7.0 ECONOMIC EVALUATION OF POWER SUPPLY ALTERNATIVES

7.1 INTRODUCTION

The objective of this section is to evaluate alternative strategies to meet the electric power demands of the Deer Island facility. An earlier study entitled "Preliminary Screening of Energy Supply Alternatives" concluded that a combination of on-site and off-site power sources is the appropriate approach. This evaluation looks at that approach in greater detail to determine the optimal number of independent off-site supplies and the optimal amount of on-site generation.

The two major alternatives presented in the preceding chapters and several variations were evaluated in terms of life-cycle present worth cost. Alternative 1, reflecting a strategy of purchasing most primary and all backup power from an electric utility (e.g., BECo), requires the installation of two independent off-site supplies, but no additional on-site generating capacity beyond the two committed 6-MW dual-fuel diesels.

Alternative 3 reflects a strategy of optimizing the mix of off-site and on-site power sources to minimize life-cycle cost. Options evaluated within this alternative included:

3A: A single off-site source and a two-unit combined cycle plant

3B: Two off-site sources and a single unit combined cycle plant.

Option 3B was evaluated with several different schedules for installation of the second off-site supply and the combined cycle unit.

Economic evaluations consisted of comparing the present worth of expenditures for power purchases, fuel purchases, operation and maintenance of generation capacity, and capital costs for off-site power supplies and new on-site generation capacity over a study period from 1991 to 2020. In each case evaluated, the same electric loads were met, as were the building heating loads. The evaluations were conducted twice, once assuming that digesters would be included in the facility, once assuming that they would not. The digesters require additional heating steam, but they provide a "free" source of fuel for the committed dual-fuel diesels and/or for combined-cycle units. Present electric rates and fuel costs were used, without real escalation. A real discount rate of 8.625 percent was used. Results are summarized in Table H-16.

7.2 ASSUMPTIONS

To perform an economic evaluation, it is necessary to make several assumptions regarding prices, electric rates, and acceptable financial performance. This subsection documents those assumptions.

TABLE H-16

ECONOMIC EVALUATION OF ALTERNATIVES

	Alternative 1 Dual off-site supply, no new generation	Alternative 3A Single off-site supply, 58 MW CC*	Alternative 3B Dual off-site supply, 25.7 MW CC
WITH DIGESTERS			
Present worth of capital expenditure ($1000)	20,100	60,823	40,423
Present worth of operation expenditures ($1000)	122,480	92,421	99,194
Total present worth ($1000)	142,580	153,244	139,617
WITHOUT DIGESTERS			
Present worth of capital expenditure ($1000)	20,100	60,823	40,423
Present worth of operation expenditures ($1000)	141,396	111,430	117,922
Total present worth ($1000)	161,496	172,253	158,345

* CC = combined cycle

7.2.1 ELECTRIC RATES

Power would be purchased from BECo at 115 kv under a rate similar to General Services Rate G-3, which is summarized in Table H-17. The G-3 rate is based on 13.8-kv service. It was assumed that the electric rates would remain stable in constant dollar terms (that is, they will increase at roughly the same rate as other prices in general).

7.2.2 FUEL

The price of #2 distillate oil (diesel fuel) delivered to Deer Island is roughly 52¢/gal, or $3.75/MBtu. Fuel costs are also assumed to remain stable in real terms. The price of natural gas, if it were available, would be about the same in the current market. Boston Gas has determined that it would have to assess a capital charge of $5,000,000 to provide adequate gas service for a combined-cycle power plant on Deer Island. Boston Gas has not committed sufficient reserves to meet such a demand year-round. For this reason, it is assumed for the purposes of this study that all fuel (other than digester gas) used at the facility will be distillate oil. However, MWRA should continue to investigate the availability and cost of natural gas.

7.2.3 ECONOMIC CRITERIA

Economic comparisons are based on the present worth of future expenditures (life-cycle costs) from 1991 to 2020 measured in 1987 constant dollars and discounted at a real rate of 8.625 percent per year, in accordance with guidelines established for the project. It is assumed that the 8.625 percent represents weighted cost of capital for MWRA and that an incremental investment will be attractive to MWRA if it has an internal rate of return in excess of that value.

7.3 EVALUATION OF ALTERNATIVES

This subsection describes the process of selecting and evaluating alternative power supply strategies.

7.3.1 EVALUATION MODEL

A spreadsheet model was developed to simulate the operation of various power supply strategy alternatives over the 30-year study period and to calculate the present worth of expenditures for capital and operational costs.

The first section of the model consists of assumptions and data common to all alternatives in a comparison: discount rate, base years for prices and present worth, fuel prices, electric rates, general descriptions of generating units, a non-dimensional electric load duration curve, forecast peak electric loads for each group of years, forecast heating loads and digester gas quantities, and retirement schedules for existing and committed capacity. This section also contains intermediate calculations of items such as period present worth factors and minimum required capacity. Table A-1 in the Attachment is a printout of this section of

TABLE H-17

BECO PURCHASE POWER RATES

Demand charge(a)

November-June:	$6.74/kw-mo.
July-October:	$15.76/kw-mo.

Energy Charge(a)

	Onpeak hrs	Offpeak hrs(b)
November-June:	2.912¢/kWH	0.703¢/kwh
July-October:	3.046¢/kWH	0.472¢/kwh

Fuel adjustment charge(c): 2.047¢/kWH

NOTES:

(a) Taken from the Boston Edison Company's General Service Rate G-3, effective 16 July 1986.

(b) On-peak hours: 8 a.m. - 9 p.m. EST, 9 a.m. - 1 p.m. EDT, weekdays.
Off-peak hours: all other hours

(c) Provided by Peter Moloney of BECo over telephone on 24 September 1986; applicable from August through October of 1986.

the spreadsheet.

The next section of the spreadsheet consists of input describing a particular strategy alternative and the resulting capital expenditures, energy balances, annual costs, and total present worth of costs. Table A-2 in the Attachment is a sample printout of such a section. A final section consists of working tables used to dispatch load to available power sources during each time period.

The total present worth cost is the sum of the present worth of capital expenditures and the present worth of operating expenditures. Peak and off-peak purchased energy are calculated through a dispatch algorithm that uses the load duration curve and allocates horizontal bands of its area (total energy) to supply sources as the basis of incremental cost and capacity (adjusted for availability). When digester gas is available, the energy it can produce in the committed 6-MW diesels and any new combined-cycle capacity is dispatched first at zero cost. After that, the incremental cost of power from the engines and combined-cycle units burning distillate oil is compared with the peak or off-peak purchase rate plus fuel adjustment charge to determine if on-site capacity should be operated or left in reserve. On-site generation is adjusted for extraction steam where appropriate. Off-site purchases fill in any energy requirements not met by the on-site capacity.

Fuel consumption and annual expense are determined based on the operation of each on-site generating source and on the amount of heating load that cannot be met by means of cogeneration. Operation and maintenance expense is based on installed on-site generation capacity.

7.3.2 SINGLE OFF-SITE SUPPLY OPTIONS

An additional power source, beyond existing and committed on-site generation and MECo capacity, will be required at Deer Island by the beginning of 1992. At that time, peak loads are forecast at 28.85 MW (plus 6-MW for engine-driven pumps), while capacity adjusted for outage of the largest unit (N-1 capacity) would be 9.5 MW. (Critical load at that time would be 25.05 MW.) Addition of only the 70 MW off-site supply at this time would meet normal demand, but would not provide sufficient capacity to cover critical load in the event of an off-site supply outage. Installation of only the combined-cycle plant at this time could meet normal requirements, as well as critical loads with one gas turbine out of service. Considering the possibility that the full-capacity (70 MW) off-site supply might not be completed by January 1992 and the fact that to meet reliability criteria, the combined-cycle plant would be required by that date anyway, the single off-site power supply strategy was defined as installation of the 58 MW combined-cycle by the end of 1990 and installation of the full-capacity off-site supply no later than the end of 1994.

Results of model runs for this strategy (Alternative 3A) are included in the Attachment and are summarized as follows:

	With Digesters	Without Digesters
Present worth of capital expenditure ($1,000)	60,823	60,823
Present worth of operating expenditure ($1,000)	92,421	111,430
Total present worth ($1,000)	153,245	172,254

7.3.3 DUAL OFF-SITE SUPPLY OPTIONS

As with the single off-site power supply cases, it was determined that the first new permanent source of supply should be made available by the end of 1991. The remaining issue, then, was to determine the best time to schedule a second off-site supply and any on-site generation that might be justified by annual electric cost savings. With the two off-site supplies in place, no on-site capacity is required to meet minimum reliability criteria.

If no new on-site generation or immediate power supply is installed, the second permanent off-site supply is also required in late 1991 to cover the 1991 increases in critical loads, which would then exceed existing and committed on-site capacity. This defines the base dual-supply strategy of Alternative 1. This strategy may not be feasible, however, due to the uncertainty that the two off-site supplies can be installed by that date. Variations on the mixed source strategy (Alternative 3B) centered on the size of a single combined-cycle unit (15 or 25.7 MW) and the timing of both the on-site and second off-site sources. It was found that, with or without digesters, the alternative with the lowest present worth cost alternative would require the immediate and first off-site supply to be in service by the end of 1991 and the combined-cycle plant to be in place by the end of 1994. Very close in present worth cost, however, was a strategy requiring the combined-cycle plant to be in place first (1991) and the second off-site supply to be installed later (1994).

Results of the evaluation model runs are provided in the Attachment and are summarized in Table H-18.

7.4 CONCLUSIONS

7.4.1 OFF-SITE POWER SUPPLY

Differences in present worth costs between the single and the dual off-site power supply alternatives are relatively small. The dual off-site supply approach, however, provides significant flexibility in dealing with future loads, fuel prices, and electric rates.

TABLE H-18

PRESENT WORTH COSTS OF DUAL OFF-SITE POWER SUPPLY OPTIONS

	Alternative 1, no new generation	Alternative 3B: Second off-site in 1991, C.C. in 1994	Alternative 3B: Second off-site in 1994, C.C. in 1991
WITH DIGESTERS, $1000			
PW of capital expenditure	20,100	36,843	40,423
PW of operating expenditure	122,480	102,718	99,194
Total PW cost	142,580	139,561	139,617
WITHOUT DIGESTERS, $1000			
PW of capital expenditure	20,100	36,843	40,423
PW of operating expenditure	141,396	121,494	117,922
Total PW cost	161,496	158,337	158,345

7.4.2 ADDITIONAL ON-SITE GENERATION

Whether or not a second off-site power supply is provided, on-site generation has value in that it reduces demand and peak energy charges from BECo. A large, two-unit 58 MW station is required in the case of the single off-site supply to cover critical loads in the event of a power failure coincident with a generating unit that is out of service. In the dual off-site supply case, economics indicate that a unit in the 25-MW size range is appropriate. This unit, in conjunction with existing and committed capacity, could generate most of the facility's normal loads during peak electric rate periods and could provide a major portion of critical loads, even during a massive blackout condition that might affect both off-site supplies. Considering the uncertainty regarding the date when a second off-site supply could be installed, the strategy of installing the combined-cycle plant before the second off-site supply is installed is the most attractive, despite a slightly higher present worth cost.

7.4.3 IMPACT OF DIGESTERS

The use of digesters in the treatment process, with their associated heating loads and gas production, results in a reduction of present worth energy costs, regardless of the strategy selected. Most of the gas can be used in the already committed dual-fuel diesel engines, and the heat load can be met by waste heat from those engines. Consequently, the choice of power supply strategy is not affected by the existence or nonexistence of the digesters. Differential present worth costs among the strategies evaluated are similar in either situation.

7.4.4 SENSITIVITY OF RESULTS

Fuel price

If fuel price were to change dramatically relative to power cost and capital costs, the lowest present worth strategy would be different. An increase from $3.75/MBtu to $6.00/MBtu would make the dual off-site supply/no new on-site generation alternative the preferred choice. With a decrease to $2.00/MBtu, however, the preferred choice remains dual off-site supply with a small combined-cycle plant. It is unlikely that a slightly lower electric rate than the one used (G-3 at 115 kv vs at 13.0 kv) would change the preferred alternative.

Discount rate

If the effective cost of capital to the MWRA is lower than 8.625 percent (real), this would favor a larger combined cycle-plant, with or without a second off-site supply. A substantially higher cost of capital would tend to favor the dual off-site supply/no new on-site generation alternative.

8.0 ENVIRONMENTAL CONSTRAINTS

8.1 AIR QUALITY

Preliminary estimates of the potential air quality impacts associated with the operation of power- and heat- generating equipment for the Deer Island wastewater treatment plant were made for the various project phases relative to existing operations and for comparison with air quality standards. The applicable ambient air quality standards for the Commonwealth of Massachusetts are the same as the National Ambient Air Quality Standards (NAAQS) and are shown in Table H-19. The primary standards are designed to protect the public health, with an adequate margin of safety, while secondary standards define levels considered necessary to protect the public welfare from any known or anticipated adverse effects of a pollutant. According to the Massachusetts Air Pollution Control Regulations (310 CMR 7.02), fossil and wood fuel utilization facilities that have energy-input capacities greater than 3 million Btu/hour require approval by the Department of Environmental Quality Engineering (DEQE). This approval is based in part on the condition that emissions from the facility would not result in any violations of NAAQS. In addition, the DEQE has established a 1-hour NO_x guideline of 320 ug/m^3 applicable to new or modified major sources of NO_x. DEQE policy states that any new source or modification of an existing source that will result in increased emissions of 250 tons or more per year must show it will not cause more than one exceedance per year of the 320 ug/m^3 guideline at any location with consideration of background levels. In addition, a new or modified major source of NO_x must not increase hourly NO_x concentrations by more than 32 ug/m^3 on more than one day per year when ambient hourly NO_x concentrations in excess of 320 ug/m^3 are predicted to occur.

In addition, a modification to a facility located in a non-attainment area (ambient pollutant concentrations exceed NAAQS) resulting in a significant increase in emissions of the pollutant in non-attainment, must comply with the provisions of 310 CMR 7.00, Appendix A (1)-(6), Emissions Offsets and Non-attainment Review. Since carbon monoxide (CO) and ozone are the only pollutants in non-attainment in Boston, an increase in CO emissions of 100 tons/year or more or an increase in emissions of volatile organic compounds (VOC) of 40 tons/year or more would require compliance with 310 CMR 7.00, Appendix A (1)-(6).

Along with the state regulations, the federally-mandated Prevention of Significant Deterioration (PSD) requirements may also apply, depending on the level of annual increases of the emitted pollutants. Increases in pollutant emissions would be determined relative to a baseline emission rate established by DEQE to be representative of the current facility operation. If these increases in pollutant emissions are significant as defined in 40 CFR 51.24, increases in pollutant concentrations over the baseline concentrations are limited to the available portion of the ambient air increments, as shown in Table H-20.

In regard to emissions limitations, Massachusetts has adopted the federal New Source Performance Standards (NSPS). NSPS would be applicable to gas turbines, which must approximate

TABLE H-19

STATE AND NATIONAL AMBIENT AIR QUALITY STANDARDS

Pollutant	Averaging interval	Primary Standard $\mu g/m_3$	Primary Standard ppm	Secondary Standard $\mu g/m_3$	Secondary Standard ppm
Sulfur dioxide	Annually	80	0.03	-	-
	24 hours	365	0.14	-	-
	3 hours	-	-	1,300	0.5
Particulate* matter	Annually**	50	-	50	-
	24 hours***	150	-	150	-
Carbon monoxide	8 hours	10**	9	10****	9
	1 hours	40**	35	40****	35
Ozone	1 hour	240	0.12	240	0.12
Nitrogen dioxide	Annually	100	0.05	100	0.05
Lead	3 months	1.5	-	1.5	-

$\mu g/m^3$ - micrograms per cubic meter
ppm - parts per million

* includes particles with an acrodynamic diameter $\leq$ 10 micrometers
** expected annual arithmetic mean
*** no more than one expected exceedance per year
**** mg/m^3 (milligrams per cubic meter)

TABLE H-20

PREVENTION OF SIGNIFICANT DETERIORATION (PSD), SIGNIFICANT EMISSIONS INCREASES, AND AMBIENT AIR INCREMENTS

1. Significant emissions increases

Pollutant	Emission rate (tons/year)
Carbon monoxide	100
Nitrogen oxides	40
Sulfur dioxide	40
Particulate matter	25
Ozone	40 (volatile organic compounds)

2. Ambient air increments*

Pollutant	Concentration ($\mu g/m^3$) 3hour	24hour	Annual
Particulate matter	N/A	37	19
Sulfur dioxide	512	91	20

* Class II increments

NO_x emission concentrations of 75 ppm for heat input rates greater than 100 million Btu/hr and 150 ppm for heat-input rates between 10 and 100 million Btu/hr. There is also a sulfur dioxide (SO_2) NSPS of 0.015 percent by volume for gas turbines, and the fuel cannot contain greater than 0.8 percent sulfur by weight. In addition, Massachusetts requires the use of Best Available Control Technology (BACT) for any facility modification resulting in changes in pollutant emissions. BACT is defined as an emission limitation based on the maximum degree of reduction for each applicable pollutant that the reviewing authority determines is achievable on a case-by-case basis, taking into account energy, environmental, and economic impacts.

The first step in this air quality analysis consists of characterizing pollutant emissions and resulting air quality impacts associated with the existing equipment, which consists of eight 1,500-kw Nordberg diesel engines and five 700-kw Enterprise diesel generators operated as required to meet power demand, as well as four heating boilers. The pollutant emissions and air quality impacts associated with the addition of two 6,000-kw engines (fast-track improvements in 1988) are then examined for Alternative 1 (off-site purchase) and compared with the emissions and impacts associated with existing operations on Deer Island. The Nordberg, Enterprise, and 6,000-kw diesels constitute the "committed capacity". Finally, the pollutant emissions and associated impacts for Alternatives 3A and 3B (combination on-site/off-site generation), for which on-site capacity is added via combined cycle plant(s), are assessed in relation to the current air quality impacts and applicable standards.

The various combinations of diesel pumps and generators that constitute the committed capacity and the new combined cycle plant(s) associated with primary and secondary treatment facilities are shown in the Appendix. Retirement of committed capacity units is addressed in Table H-21.

This preliminary air quality impact analysis is performed using EPA screening level computer models along with estimates of pollutant emissions obtained from EPA publications and equipment vendor data. Refined modeling using five years of meteorological data will be performed at a later time. Information on stack parameters needed for computer modeling is obtained from DEQE fuel-burning equipment registration forms (Form AP-1, DEQE 85) and from vendor-supplied data. In some cases, stack parameters, such as exit velocity, are estimated using fuel use or heat-input data. In addition, estimates of background concentrations of the criteria pollutants on Deer Island are obtained from monitoring data published by the DEQE. The details of the analysis are described in the following subsections.

8.1.1 EMISSIONS CHARACTERISTICS

The emissions characteristics needed to model the air quality impact of each piece of equipment include stack height, inside stack diameter, exit velocity, exit temperature, and pollutant emission rate. This information is obtained for the Nordberg and Enterprise diesel generators as well as for the Cleaver Brooks heating boilers from DEQE fuel-burning equipment registration forms (Form AP-1, DEQE 85). The Nordberg and Enterprise exit temperatures are assumed to be the same as those used in documentation on the Deer Island fast-track improvements. The volumetric flow for the Nordbergs and the Enterprises is calculated based on the maximum firing rate for each unit (Nordberg - 120 gal/hr, Enterprises - 60 gal/hr) and an assumed 40 lbs of

TABLE H-21

DEER ISLAND FOSSIL-FUELED EQUIPMENT INVENTORY

Period	Nordberg diesels Oper. (No.)	Stdby. (No.)	ALF (%)	Enterprise diesels Oper. (No.)	Stdby. (No.)	ALF (%)	Delaval diesels Oper. (No.)	Stdby. (No.)	ALF (%)	Combined cycle (a) Oper. (No.)	Stdby. (No.)	ALF (%)
Baseline	4	4		2	3							
1988-1989	1	4	2	4	1	2	1	1	100			
1990-1994	1	4	2	4	1	100	1	1	100			
1995-1998							1	1	24	2	0	17
- Alt 3A							1	1	24	1	1	33
- Alt 3B												
1999-2020							1	1	24	2	0	24
- Alt 3A							1	1	63	1	1	33
- Alt 3B												
Boilers (all periods)	3	1	42									

(a) Alternative 3 only
Oper. = Operating
Stdby. = Standby
ALF = Annual Load Factor

flue gas generated per pound of fuel burned. The volumetric flow for the heating boilers is also based on the maximum firing rate (12×10^6 Btu/hr) and 40 lbs of flue gas per pound of fuel burned, as well as an assumed heating value of 19,400 Btu per pound for distillate oil.

The emissions characteristics of the proposed 6,000-kw Delaval diesel generator are estimated from available vendor-supplied information. The same stack height as the Nordberg diesels is assumed for the 6,000-kw diesel generators. Stack data for the proposed combined cycle plant for Alternatives 3A and 3B are based on vendor information available for a 22-MW gas turbine. The gas-turbine emission heights used in the modeling are 34.3 m (112.5 ft), based on the EPA Good Engineering Practice Stack Height formula of 2.5 times the height of adjacent structures, which in this case is assumed to be 13.7 m (45 ft). Preliminary indications are that this stack height will pose no difficulties for air traffic at Logan Airport. The stack parameters for all equipment are given in Table H-22.

With the exception of the 6,000-kw Delaval diesel generators, the emission rates of the criteria pollutants from all equipment, including nitrogen oxides (NO_x), sulfur dioxide (SO_2), carbon monoxide (CO), volatile organic compounds (VOC), and total suspended particulates (TSP), are estimated using EPA publication AP-42. Vendor-supplied information is used for the 6,000 kw Delaval diesel generators. The emissions estimates for the diesels assume no flue-gas controls, while the gas-turbine emissions assume the use of water injection to reduce NO_x emissions to 75 ppm by volume while burning distillate that meets NSPS and is guaranteed by the manufacturer. The SO_2 emissions from the gas turbines are estimated to be less than 5 ppm by volume, which is well below the NSPS of 150 ppm. The costs developed in Section 5 include an allowance for steam or water injection. The diesel emissions of SO_2 assume the use of 0.3 percent sulfur diesel fuel. The estimated pollutant emission rates from all equipment at full load are given in Table H-23.

These fuel-use assumptions provide the worst-case estimates of pollutant emissions for the project in terms of the full load and use of distillate assumptions. Additionally, it was assumed that digester gas would not be available for use as a supplemental fuel. The use of digester gas in the diesels would reduce the estimated SO_2 emissions by approximately an order of magnitude and NO_x emissions by about 25 percent. In estimating pollutant emission rates for predicting air quality impacts associated with 1 hour, 3 hour, 8 hour, and 24 hour emission rates, it was assumed that each piece of equipment would operate at 100 percent capacity.

Pollutant emissions rates for Alternatives 1, 3A and 3B for average and peak wastewater flows for each project phase are given in Table H-24. The only difference among Alternatives 1, 3A and 3B is the addition of the combined cycle plant in 1995 for Alternatives 3A and 3B. The baseline emissions are preliminarily based on actual fuel usage for 1985 from Form AP-1, DEQE 85. In all cases, annual emissions are based on the preliminary equipment dispatching information provided in Section 7. Also, Table H-21 shows the combination of equipment assumed in estimating the emissions shown in Table H-24. Table H-24 indicates that annual NO_x emissions will increase for the 1988 and 1990 project phases and decrease for the 1995 and 1999 phases, except for Alternative 3B in 1999. The largest increase in annual NO_x emissions occurs in 1990 with an annual increase of 682 tons/yr. SO_2 emissions will increase for the 1988 and 1990 project phases with the largest increase of 78 tons/year occurring in 1990. The only

TABLE H-22
STACK PARAMETERS

Equipment	Stack height (m)	Stack diameter (m)	Exit velocity (m/sec)	Exit temperature (°K)
Nordberg diesel engine (1.5 MW)	15.2	0.61	22.3	533
Enterprise diesel generator (0.7 MW)	12.2	0.36	32.6	533
Delaval diesel generator (6 MW)	15.2	1.00	16.5	705
Cleaver Brooks heating boilers	10.7	1.37	7.5	422
Gas turbine (22 MW)	34.3	2.83	27.4	449

TABLE H-23

POLLUTANT EMISSION RATES FOR ALL EQUIPMENT

	Pollutant Emission Rate (lbs/hr)				
Equipment	NOx	SO_2	CO	TSP	VOC
Nordberg diesel engine	60.0	5.4	15.6	6.0	1.6
Enterprise diesel generator	30.0	2.7	7.8	3.0	0.8
Delaval diesel generator	171.4	19.1	9.1	0.6	0.4
Cleaver Brooks heating boiler	4.7	4.0	0.4	0.6	0.02
Gas turbine (22 MW)	99	11.0	48.0	15.6	17.4

TABLE H-24

POLLUTANT EMISSION RATES FOR ALTERNATIVES 3A AND 3B

Year	Pollutant Emission Rate NOx	SO_2	CO	TSP	VOC
Baseline					
Avg. flow (a)	626	76	159	60	16
Peak flow (b)	314	39	79	32	8
1988-1989					
Avg. flow	793	108	46	5	3
Peak flow	365	47	57	32	5
1990-1994					
Avg. flow	1,308	154	180	57	16
Peak flow	365	47	57	32	5
1995-1998					
Alternative 1					
Avg. flow	251	47	14	4	1
Peak flow	185	31	10	2	0.5
Alternative 3A					
Avg. flow	353	58	83	27	26
Peak flow	383	53	102	32	34
Alternative 3B					
Avg. flow	576	83	164	53	56
Peak flow	284	42	56	17	17
1999-2020					
Alternative 1					
Avg. flow	251	47	14	4	1
Peak flow	185	31	10	2	0.5
Alternative 3A					
Avg. flow	414	65	112	36	37
Peak flow	383	53	102	32	34
Alternative 3B					
Avg. flow	641	90	96	28	26
Peak flow	284	42	56	17	17

(a) Average flows are measured in tons/yr.

(b) Peak flows are measured in lbs/hr.

[illegible]

increase in annual SO_2 emissions for the 1995 and 1999 periods occurs in 1999, for Alternative 3B at 14 tons/year. The annual CO emissions will increase only for the 1990-1994 period at 21 tons/year. TSP emissions will decrease for all project phases. The largest VOC emissions increase (21 tons/year) will occur in 1999 for Alternative 3A. Alternative 1 emissions in 1995 and 1999 are all lower than baseline emissions.

It should be noted again that the use of digester gas in the 6,000-kw Delaval diesels would significantly reduce the NO_x and SO_2 emissions for the committed capacity. In addition, the current practice of flaring digester gas has not been taken into account in the existing emissions (baseline). Using digester gas in the diesels could result in significant net decreases in NO_x and CO emissions. In one documented case, the use of digester gas as a diesel fuel created a net 50-percent decrease in emissions of NO_x and CO, compared to what the site released when the bulk of the gas was flared.

The predicted impacts of these emissions on ambient air quality are discussed below.

8.1.2 BACKGROUND AIR QUALITY

Background air quality concentrations are determined from the air quality monitoring data published by the Massachusetts DEQE. Wherever possible, data from the Deer Island monitoring station are used to determine background concentrations. For averaging times less than annual average, the highest monitored value from the latest three years of data was chosen as background. The largest annual average value for the three most recent years of data was also chosen as background. If data from Deer Island were not available for a given pollutant, the highest monitored values from nearby stations (Long Island, East Boston, Chelsea) for the three most recent years of data were chosen.

Background NO_x concentrations at Deer Island are estimated to be 61 $\mu g/m^3$ on an annual basis. This concentration is based on a 1984 monitored value of 61 $\mu g/m^3$ at East Boston. This could be considered a conservative value, since the only valid annual NO_2 concentration monitored on Deer Island itself was 28 $\mu g/m^3$ in 1983.

For SO_2, 3- and 24-hour concentrations of 367 $\mu g/m^3$ and 254 $\mu g/m^3$ were chosen as background levels for Deer Island. The 3-hour SO_2 concentration was the highest recorded at Powder Horn Hill in Chelsea in 1984, and the 24-hour value was the highest monitored on Long Island in 1984. Again, these are considered to be conservative values since the only recorded 3- and 24-hour SO_2 concentrations on Deer Island were 290 and 118 $\mu g/m^3$, respectively. The annual average SO_2 background concentration of 34 $\mu g/m^3$ was recorded at East Boston in 1984.

For CO, 1-hour and 8-hour concentrations of 29,000 $\mu g/m^3$ and 10,000 $\mu g/m^3$ were chosen for background at Deer Island, based on 1985 and 1983 monitoring results, respectively, in East Boston. The 8-hour value of 10,000 $\mu g/m^3$ equals the standard that reflects Boston's non-attainment status for CO. There is no CO data available for Deer Island.

The highest monitored 24-hour and annual TSP concentrations of 130 and 54 $\mu g/m^3$, respectively, in East Boston in 1984 were also selected as background values.

It should be noted that these background levels were chosen without regard to the possible influence of existing pollutant emissions at Deer Island. Therefore, the background levels may be higher than what is truly indicative of the ambient concentrations caused by other sources.

8.1.3 MODELING

The air quality impacts of the fossil-fueled equipment for each phase of the project are estimated using the EPA Industrial Source Complex Short Term (ISCST) model in the screening mode for short-term impacts and the Industrial Source Complex Long-Term (ISCLT) model for annual average impacts. These computer models are executed for each piece of power-generating equipment, assuming full-load operation, to obtain estimates of the maximum impacts of the individual equipment operation. The air quality impact of each project phase is then determined by summing the predicted concentrations to obtain the maximum impact for those combinations of equipment needed to supply the power demand for each project phase. Maximum predicted air quality impacts are determined for NO_x (1-hour and annual average), SO_2 (3- and 24-hour and annual average), CO (1- and 8-hour) and TSP (24-hour and annual average). The 3-, 8-, and 24-hour concentrations are estimated from the 1-hour concentrations calculated by ISCST using the correction factors from the EPA "Guidelines for Air Quality Maintenance Planning and Analysis," Volume 10. More refined modeling using five years of hour-by-hour meteorological data will be performed after the power equipment usage and siting are finalized.

For modeling purposes, all Nordberg diesel emissions were assumed to originate from the center of the pump house, and the Enterprise diesel and Cleaver Brooks boiler emissions were assumed to emanate from the center of the building housing this equipment. The location of the Delaval diesel emissions for modeling purposes was estimated based on the proposed siting of these diesels. Likewise, the location of the gas turbine emissions is estimated based on the latest preferred siting of the new power station for Alternative 3B.

It should also be noted that the terrain elevations associated with the Deer Island drumlin and the proposed berm around the island were utilized in the model runs, but that public access to these areas was assumed to be restricted. Therefore, the maximum impacts resulting from this analysis are assumed to occur off the island or beyond security areas.

ISCST and ISCLT modeling assumptions are as follows:

- rural mode
- buoyancy-induced dispersion
- building downwash for diesels and boilers only
- gradual plume rise for diesels and boilers only
- no stack tip downwash for diesels and boilers only
- receptor elevations used
- air temperature - A:288° K, B:288° K, C:288° K, D:284° K, E:280° K, F:280° K (ISCLT); 284° K (ISCST)
- mixing heights - A:1200 m, B-D:800 m (ISCLT); 5000 m (ISCST)

- o downwind distances - 100-1,000 m:100 m increments
  1,000-3,000 m:200 m increments
  3,000-5,000 m:500 m increments
- o directions - 10° sectors

The meteorological conditions used in the ISCST runs in the screening mode are the same conditions used in the PTPLU screening model. These conditions are considered for all 10-degree wind direction sectors utilized in the model receptor grid.

The meteorological data for ISCLT modeling consist of a joint frequency distribution of wind speed, wind direction, and stability class based on 12 years (1970-1981) of Boston (Logan Airport) data. Assumed air temperatures and mixing heights are chosen based on the recommendation of the ISC User's Guide.

In addition to the model runs, a cavity analysis was performed in accordance with the procedures of Appendix C to the Regional Workshops on Air Quality Modeling. The results of that analysis demonstrated that the diesel and boiler emissions would be entrained into the building cavity, but that the building cavity did not extend beyond the plant boundary.

8.1.4 RESULTS AND CONCLUSIONS

The changes in air quality impacts for the power and pump stations for each phase for Alternatives 1, 3A and 3B are shown in Table H-25. This table indicates that in 1995 and 1999, all alternatives would improve air quality in the area for all pollutants relative to existing emissions. For the other time periods, Table H-25 indicates that SO_2 concentrations would increase slightly; NO_2 concentrations would increase slightly, with the exception of the annual value in 1988; and CO concentrations would generally decrease. In any event, the preliminary indication is that these alternatives would meet ambient air quality standards with the possible exception in 1988 and 1990 of the 1-hour NO_2 DEQE policy guideline. Since the 1990-1994 period is the only one in which NO_x emissions increase more than 250 tons/year (see Table H-24), the DEQE NO_2 policy of not exceeding 320 $\mu g/m^3$, including background, or not increasing the hourly impact by more than 32 $\mu g/m^3$ would apply. Since Table H-25 indicates an increase of 46 $\mu g/m^3$ in the hourly NO_2 concentration from the baseline to 1990, a potential for a violation of this policy exists. However, a final determination on the baseline emissions, along with the refined modeling analysis, is needed before any meaningful conclusions can be drawn.

The reason for the improvements in air quality resulting from the added generating capacity can be seen in Table H-26, which shows the air quality impact of the individual generating equipment. This table indicates that the new equipment (6,000-kw diesel generators and gas turbines) is capable of generating much more power with a smaller air quality impact than the existing equipment. For the 6,000-kw diesel generators, the smaller impact is related to lower pollutant-emission rates and the higher plume rise associated with the larger volumetric flow and higher exhaust temperature. The gas-turbine impacts are much smaller per kilowatt than the diesels, mainly because of the much smaller pollutant emission rates associated with the use of

TABLE H-25

CHANGES IN AIR QUALITY CONCENTRATIONS ($\mu g/m^3$) OF ALTERNATIVES 1, 3 AND 3B COMPARED TO EXISTING IMPACTS

	NO_x		SO_2			CO		TSP	
Year	1-hr	Annual	3-hr	24-hr	Annual	1-hr	8-hr	24-hr	Annual
Baseline	0	0	0	0	0	0	0	0	0
1988-1989	46	-7	17	7	-1	-57	-39	-11	-1.8
1990-1994	46	7	17	7	+1	-57	-39	-11	0.3
1995-1998									
Altern. 3A	-791	-14	-53	-24	-2	-282	-197	-47	-1.0
Altern. 3B	-803	-14	-54	-24	-2	-287	-201	-47	-2.0
1999-2020									
Altern. 3A	-791	-14	-53	-24	-2	-282	-197	-47	-2.0
Altern. 3B	-803	-12	-54	-24	-2	-287	-201	-47	-2.0

TABLE II-26

ESTIMATED AIR QUALITY IMPACTS OF INDIVIDUAL EQUIPMENT

	Maximum Pollutant Concentrations ($\mu g/m3$)								
	SO_2			NO_x		CO			TSP
Year/Equipment	3hr	24hr	Ann.	1hr	Ann.	1hr	8hr	24hr	Ann.
Baseline									
Nordbergs (4)*			1		9				1
Enterprises (2)	98	44	1	1,209	7	314	220	49	1
Boilers (3)	39	17	1	50	1	5	3	3	0.1
Total	137	61	3	1,259	17	319	223	52	2.1
1988-1989									
Nordberg (1)*			<0.1		0.1				0.1
Enterprises (4)	75	33	<0.1	922	0.5	240	168	37	0.1
Delaval (1)	33	14	1	323	8	17	12	1	<0.1
Boilers (3)	46	21	1	60	1	5	4	3	0.1
Total	154	68	2	1,305	10	262	184	41	0.3
1990-1994									
Nordberg (1)*			<0.1		0.1				0.1
Enterprises (4)	75	33	2	922	22	240	168	37	2.2
Delaval (1)	33	14	1	323	8	17	12	1	<0.1
Boilers (3)	46	21	1	60	1	5	4	3	0.1
Total	154	68	4	1,305	31	262	184	41	2.4
1995-1998									
Alternative 3A									
Delaval (1)	39	17	0.2	388	2	21	14	1	<0.1
Gas Turbines (2)	2	1	<0.1	24	<0.1	11	8	1	<0.1
Boilers (3)	43	19	1	56	1	5	4	3	0.1
Total	84	37	1	468	3	37	26	5	0.1
Alternative 3B									
Delaval (1)	39	17	0.2	388	2	21	14	1	<0.1
Gas Turbines (2)	1	1	<0.1	12	<0.1	6	4	1	<0.1
Boilers (3)	43	19	1	56	1	5	4	3	0.1
Total	83	37	1	456	3	32	22	5	0.1

TABLE II-26

ESTIMATED AIR QUALITY IMPACTS OF INDIVIDUAL EQUIPMENT
(Continued)

	Maximum Pollutant Concentrations ($\mu g/m3$)								
	SO_2			NO_x		CO			TSP
Year/Equipment	3hr	24hr	Ann.	1hr	Ann.	1hr	8hr	24hr	Ann.
1995-2020									
Alternative 3A									
Delaval (1)	39	17	0.2	388	2	21	14	1	<0.1
Gas Turbines (2)	2	1	<0.1	24	<0.1	11	8	1	<0.1
Boilers (3)	43	19	1	56	1	5	4	3	0.1
Total	84	37	1	468	3	37	26	5	0.1
1995-1998									
Alternative 3B									
Delaval (1)	39	17	0.4	388	4	21	14	1	<0.1
Gas Turbines (2)	2	1	<0.1	24	<0.1	11	8	1	<0.1
Boilers (3)	43	19	1	56	1	5	4	3	0.1
Total	84	37	1	468	5	37	26	5	0.1

*Short-term impacts for Nordbergs and Enterprises are combined.

distillate and emission controls (water injection). Thus, replacing existing equipment with new generating equipment as much as possible results, for the most part, in improved air quality.

In regard to the non-attainment issue for CO and ozone, it was stated earlier that an increase in CO emissions of 100 tons/year or more or an increase in VOC emissions of 40 tons/year or more would require compliance with 310 CMR 7.00, Appendix A. Table H-24 indicates that the maximum increase in CO emissions is expected to be only 21 tons/year, well below the 100 tons/year limit. This table also indicates that the maximum increase in VOC emissions is expected to be approximately 21 tons/year, well below the 40 tons/year limit. Therefore, the application of the requirements of 310 CMR 7.00, Appendix A, to VOC emissions would not be required.

In regard to the application of the PSD requirements to this project, Table H-24 indicates NO_x and SO_2 emissions increases of 682 and 78 tons per year, respectively, in the 1990 to 1994 period. Since these increases are larger than the "significant" increase definition given in Table H-20 for these pollutants, compliance with PSD SO_2 and TSP increment consumption would apply to this phase of the project. However, as indicated in Table H-25, the increases in SO_2 concentrations are very small compared to the Class II increments shown in Table H-20. Although the available portion of the increment is not known at this time, it seems unlikely that PSD increments would impose constraints on the project.

It should be emphasized that this screening analysis has been performed in a preliminary and conservative manner, as described in Section 8.1.3. More detailed analyses utilizing hourly meteorological data for five years are required for final impact assessments.

8.2 NOISE EMISSIONS

The diesel engines and combustion turbines are expected to be the largest and most difficult-to-control sources of on-site operational noise. The primary noise sources of the diesel are the exhaust and the casing. Air intake is also a significant contributor. These engines would have to be enclosed and would require exhaust silencers, which provide the maximum available silencing. The primary sources of noise for the gas turbines are the compressor intake, the combustion exhaust, and auxiliary equipment. The gas turbines would also require silencing measures resulting in state-of-the-art reduction levels. The total sound level from both types of equipment with commercially available silencing is of the same order of magnitude. It should be noted that the preliminary costs developed in Section 7 include an allowance for enclosures and intake and exhaust silencers, which are commercially available and are typically provided for the diesels and gas turbines. A more refined analysis to be performed under facilities planning activities is required for further definition of equipment selection.

As part of the Deer Island Secondary Treatment Facilities Plan, activities are currently underway to characterize ambient noise levels at Deer Island and to develop evaluation criteria, including numeric noise limits, to be used on the project. MWRA is committed to

complying with all of the legal standards of both the City of Boston and the DEQE and has further set a goal of going beyond legal compliance and providing the highest is achievable levels of noise control. A detailed noise analysis is contained in Section 11.4.4 of Volume III.

Nevertheless, based on a review of previous reports addressing Deer Island noise concerns and the preliminary types and amounts of power generation equipment for the two alternatives, noise level concerns are not expected to constrain the selection of either of the alternatives evaluated. It is more a case of selecting the appropriate noise control measures to be incorporated into each alternative so that any resulting noise impacts are minimized.

9.0 THIRD-PARTY INTEREST

In accordance with Work package 60A, third-party interest in developing, owning, and operating the power plant portion of the Deer Island wastewater treatment facility was solicited. Swift River/Hafslund Company (SR/H) expressed interest in pursuing involvement in the project.

SR/H outlined its capabilities and proposed approach relative to all phases of the power plant project development and operation. SR/H's approach and scope of responsibilities would be as follows:

1. Fuel and Power Sales Contracts - Negotiate fuel, electricity, and transmission contracts.

2. Regulatory Permitting - Assess permitting requirements and obtain permits, using consultants as required.

3. Project Financing - Evaluate and negotiate construction and long-term financing.

4. Project Design and Construction

    a. Site Review - Assess support or opposition by community and regulatory agencies. Determine fuel and water availability and environmental impact.

    b. Specification Preparation - Develop design basis for preparation of project specifications by a consulting engineer.

    c. Selection of Construction Contractor and Project Engineer - Qualify and select, via competitive bidding, a construction contractor and project engineer.

    d. Equipment Procurement and Fabrication - Oversee and maintain final approval of this effort, which is the direct responsibility of the construction contractor and project engineer.

    e. Performance Testing - Witness, evaluate, and accept performance tests.

5. Project Operations - Under a separate fixed-price contract hire, train, supervise, and pay operating personnel; operate and monitor plant; perform routine preventive maintenance; prepare operating records, reports, and annual maintenance budgets.

6. Project Insurance - Define and administer the appropriate insurance obligations.

Since third-party interest exists, MWRA should consider issuing an RFP for an on-site power plant owned and operated by a third party.

10.0 CONCLUSIONS AND RECOMMENDATIONS

10.1 CONCLUSIONS

10.1.1 OFF-SITE POWER SUPPLY

Differences in present worth costs between the single and the dual off-site power supply alternatives are relatively small. While the single-supply alternative might be optimized by phased installation of the on-site power plant resulting in a lower present worth cost than the lowest-cost dual-supply alternative considered, the difference is small considering the significant flexibility offered by the dual off-site supply approach in dealing with future loads, fuel prices, and electric rates, the dual off-site alternative is recommended.

10.1.2 ADDITIONAL ON-SITE GENERATION

Even with two off-site sources of power, on-site generation has value in that it reduces demand and peak energy charges from BECo. A large, two-unit station would be required with a single off-site supply to cover critical loads in the event of a power failure coincident with a generating unit being out of service. In the dual off-site supply case, economics indicate that a unit in the 25-MW size range is appropriate. This unit, in conjunction with existing and committed capacity, can generate most of the facility's normal loads during peak electric rate periods and could provide a major portion of critical loads, even during a massive blackout condition that might affect both off-site supplies.

10.1.3 IMPACT OF DIGESTERS

The use of digesters in the treatment process, with their associated heating loads and gas production, results in a reduction of present worth energy costs, regardless of the strategy selected. Most of the gas can be used in the already committed dual-fuel diesel engines, and the heat load can be met by waste heat from those engines. Consequently, the choice of power supply strategy is not affected by the existence or nonexistence of the digesters. Differential present worth costs among the strategies evaluated are similar in either situation.

Based on predicted digester gas quantities from Table H-13, sufficient digester gas will be available in 1995 to generate 5,800 kw if used as produced and 13,900 kw if 16-hour storage is provided for peak sharing. In 1999 these needs will increase to 11,000 kw and 25,000 kw, respectively.

10.1.4 SENSITIVITY OF RESULTS

Fuel price

If fuel price were to change dramatically relative to power cost and capital costs, the lowest

present worth strategy would be different. An increase from \$3.75/MBtu to \$6.00/MBtu would make the dual off-site supply/no new on-site generation alternative the preferred choice. A decrease to \$2.00/MBtu would make the single off-site supply, large combined-cycle plant alternative the preferred choice.

Discount rate

If the effective cost of capital to the MWRA is lower than 8.625 percent (real), this would favor a larger combined cycle-plant, with or without a second off-site supply. A substantially higher cost of capital would tend to favor the dual off-site supply/no new on-site generation alternative.

10.2 RECOMMENDATIONS

Based on the energy projections provided in Section 4.0, the economic analysis developed in Section 7.0, and the environmental considerations discussed in Section 8.0, the following recommendations are made:

1. Begin work immediately to install power transmission line(s) interconnecting the Deer Island facilities to BECo's power system grid. To meet the required in-service dates, formal application should begin immediately. The wheeling of power from BECo to Deer Island through Mass Electric's system grid for immediate power should also start as soon as possible.

2. Provide duplicate power transmission lines and some amount of additional on-site capacity to meet reliability design criteria and be in accordance with economic evaluation results.

3. Add 25,700 kw of on-site power- and heat-generating capacity capable of burning No. 2 fuel oil and natural gas in addition to that already committed by the Fast-Track Improvements Program. Continue to investigate the availability and cost of an off-island source of natural gas.

4. Consider retaining a private party, with specialized expertise in the operation and maintenance of power- and heat-generating systems, to operate and maintain all on-site power- and heat-generating equipment. In addition, the possibility of private ownership of this on-site capacity should also be assessed.

It is further recommended that MWRA re-evaluate this study prior to authorizing the installation of the combined cycle power plant and the second 115 kv permanent feeder from Chelsea. The results of this study are based on current economics, estimated load projections, and the ability of BECo to provide long-term reliable power from two separate sources. If in the future, additional on-site capacity is found to be desirable, an evaluation of air quality and noise impacts should be performed.

10.3 IMPLEMENTATION PLAN

The recommendation to proceed to establish an off-site power supply for Deer Island can best be implemented by taking steps now to initiate the necessary applications for an off-site electrical power supply. The application for service will also begin the process of negotiating an agreement with the utilities. The process must be started now to ensure a comprehensive and timely plan for providing power to Deer Island during construction and operation of the facilities.

The following efforts should be implemented in the near future:

1. MWRA should initiate immediate formal application with Boston Edison for providing both interim and permanent electric power to Deer Island in a timely and environmentally acceptable manner.

2. The process of engineering, design, environmental permitting, construction, start-up, and test of the recommended power-generating capacity additions should be initiated.

ATTACHMENT A

TABLE A-1
ECONOMIC ASSUMPTIONS -- NO DIGESTERS

CONSTANTS:				
Discount rate (real)			8.625%	
Base year for prices			1986	
Base year for present worth			1990	
Price of fuel, $/MBtu			$3.75	
Price of electricity:				
Demand, $/kW-yr			$117	
Facilities, $/kW-yr			$0	
Energy, $/kWh	hrs			
On-peak	3389		0.02957	
Off-peak	5371		0.00626	
Fuel adjustment	8760		0.02047	
Diesels:	Heat rate	Ht recovery		O&M Cost
	9200 Btu/kWh	2381 Btu/kWh		$20 /kW-yr
New feeders:	Capacity	Capital cost		
A	70 MW	$9,500 x1000		
B	70	$10,600 x1000		
New unit data:	Heat rate	Capital cost		O&M Cost
Combined cycle	0 Btu/kWh	$0 /kW		$40 /kW-yr
	0.0 MW	0.0353 kWh/lb		
Unit availablities, h/yr		7500	85.62%	
Digester gas on-peak availablity		38.69%		

Electric load profile:

Hours	Load	Energy	Cum Energy	Cum Hours	dY/dX
0	0.0	0.0000	0.0000	8760	1.0000
0	0.1	0.0000	0.1000	8760	1.0000
0	0.2	0.0000	0.2000	8760	1.0000
10	0.3	0.0003	0.3000	8760	0.9989
430	0.4	0.0196	0.3999	8750	0.9498
1750	0.5	0.0999	0.4949	8320	0.7500
6400	0.6	0.4384	0.5699	6570	0.0194
160	0.7	0.0128	0.5718	170	0.0011
5	0.8	0.0005	0.5719	10	0.0006
4	0.9	0.0004	0.5720	5	0.0001
1	1.0	0.0001	0.5720	1	0.0000
8760		0.5720			

TABLE A-1
ECONOMIC ASSUMPTIONS -- NO DIGESTERS
(Continued)

Period definitions:						
First year	1986	1988	1991	1993	1995	1999
Last year	1987	1990	1992	1994	1998	2020
Present worth						
Operating cost	0.000	0.000	1.768	1.498	2.346	5.012
Capital cost	0.000	0.000	1.000	0.848	0.718	0.516
Electric demand, MW:						
Basic usage	0.65	0.65	0.65	2.65	2.65	2.65
Influent pumping	1.50	8.70	8.70	8.70	20.80	20.80
Construction	0.00	0.00	15.00	15.00	3.00	0.00
Nut Island flow	0.00	0.00	0.00	0.00	5.60	5.60
Air emmissions	0.00	0.00	0.00	0.00	1.25	1.50
Disinfection	0.00	0.00	0.00	0.00	0.00	0.00
Secondary trt	0.00	0.00	0.00	0.00	0.00	19.40
Primary trt	0.00	0.00	0.00	0.00	7.90	7.90
Dewatering	0.00	0.00	3.00	3.00	3.00	5.00
Annual peak	2.15	9.35	27.35	29.35	44.20	62.85
Engine driven pumps equivalent kW	12.00	6.00	6.00	6.00	0.00	0.00
Total equiv MW	14.15	15.35	33.35	35.35	44.20	62.85
Critical load, MW	14.15	15.35	30.35	32.35	41.20	44.45

TABLE A-1
ECONOMIC ASSUMPTIONS -- NO DIGESTERS
(Continued)

First year	1986	1988	1991	1993	1995	1999
Last year	1987	1990	1992	1994	1998	2020
Electric energy, MWh/yr:						
LF = 57.20%	10773	46849	137040	147061	221469	314916
Engine driven pump energy, equiv MWh/yr:						
	60127	30064	30064	30064	0	0
Total equivalent energy, MWh/yr:						
	70900	76913	167104	177125	221469	314916
Committed capacity						
Existing diesels						
1.5 MW	8	4	4	4	0	0
0.7 MW	5	5	5	5	0	0
0.3 MW	2	0	0	0	0	0
New Dual fuel						
6.0 MW	0	2	2	2	2	2
Total MW	16.1	21.5	21.5	21.5	12.0	12.0
Largest unit	1.5	6.0	6.0	6.0	6.0	6.0
Secure MW	14.6	15.5	15.5	15.5	6.0	6.0
Steam requirements, MBtu/h avg						
Digesters	0.0	0.0	0.0	0.0	0.0	0.0
Blgs & tunnels	9.8	9.8	9.8	9.8	9.8	9.8
Digester gas output:						
Average, MBtu/h	0.0	0.0	0.0	0.0	0.0	0.0
Annual, MBtu/yr	0	0	0	0	0	0
Capacity required, MW	0.0	0.0	17.9	19.9	38.2	56.9

TABLE A-2

ALTERNATIVE 1 - NO NEW GENERATION, DUAL UTILITY FEEDER, NO DIGESTERS

First year	1986	1988	1991	1993	1995	1999
Last year	1987	1990	1992	1994	1998	2020
New capacity, units						
70 MW feeder	0	0	2	2	2	2
0.0 MW C.C.	0	0	0	0	0	0
Cumulative MW						
Committed	16.1	21.5	21.5	21.5	12.0	12.0
Feeder	0.0	0.0	140.0	140.0	140.0	140.0
C.C.	0.0	0.0	0.0	0.0	0.0	0.0
Total	16.1	21.5	161.5	161.5	152.0	152.0
Largest unit	1.5	6.0	70.0	70.0	70.0	70.0
Secure MW	14.6	15.5	91.5	91.5	82.0	82.0
Capital costs, 1000$						
Feeder	$0	$0	$20,100	$0	$0	$0
C.C.	$0	$0	$0	$0	$0	$0
Total	$0	$0	$20,100	$0	$0	$0
Present worth	$0	$0	$20,100	$0	$0	$0
Cumulative	$0	$0	$20,100	$20,100	$20,100	$20,100
Surplus capacity, MW	0.5	0.2	61.2	59.2	40.8	37.6
Utility demand, MW	0.0	0.0	14.9	16.9	33.9	52.6
Energy generated, MWh/yr						
On digester gas						
on-peak	0	0	0	0	0	0
off-peak	0	0	0	0	0	0
On purchased fuel						
On-peak						
C.C.	0	0	0	0	0	0
Diesel	27431	29758	60340	61152	34821	34821
Off-peak						
C.C.	0	0	0	0	0	0
Diesel	43468	47155	0	0	0	0
Total	70900	76913	60340	61152	34821	34821

TABLE A-2
ALTERNATIVE 1 - NO NEW GENERATION, DUAL UTILITY FEEDER, NO DIGESTERS
(Continued)

Energy purchased, MWh/yr						
On-peak	-0	0	4313	7378	50866	87021
Off-peak	-0	0	102450	108594	135781	193074
Total	-0	0	106764	115972	186647	280095
Grand total	70900	76913	167104	177125	221469	314916
Error	-0	0	-0	-0	0	0
Heating requirements, MBtu/yr						
Total heating	33215	33215	33215	33215	33215	33215
on/off pk	52633	52633	52633	52633	52633	52633
Diesel heat	0	0	0	0	0	0
on/off pk	0	0	0	0	0	0
CC extraction	0	0	0	0	0	0
on/off pk	0	0	0	0	0	0
From boilers	85848	85848	85848	85848	85848	85848
Equivalent fuel	100998	100998	100998	100998	100998	100998
Annual costs, $1000/yr						
Electric utility						
Facilities	$0	$0	$0	$0	$0	$0
Demand	$0	$0	$1,748	$1,982	$3,969	$6,151
On-peak energy	($0)	$0	$128	$218	$1,504	$2,573
Off-peak energy	($0)	$0	$641	$680	$850	$1,209
Fuel adjustment	($0)	$0	$2,185	$2,374	$3,821	$5,734
Total electric	($0)	$0	$4,703	$5,254	$10,144	$15,667
Heating fuel	$379	$379	$379	$379	$379	$379
Engine fuel	$2,446	$2,654	$2,082	$2,110	$1,202	$1,202
Comb cycle fuel	$0	$0	$0	$0	$0	$0
Total fuel	$2,825	$3,033	$2,461	$2,489	$1,580	$1,580
O&M cost	$322	$430	$430	$430	$240	$240
Total cost	$3,147	$3,463	$7,593	$8,173	$11,964	$17,487
Present worth	$0	$0	$13,426	$12,247	$28,071	$87,652
Cumulative	$0	$0	$13,426	$25,673	$53,745	$141,396
TOTAL PRES. WORTH	$0	$0	$33,526	$45,773	$73,845	$161,496

SUMMARY PRESENT WORTH COST:
$1,000

Capital:	$20,100
Operating:	$141,396
Total:	$161,496

TABLE A-3

ALTERNATIVE 3A - 58MW CC, SINGLE UTILITY FEEDER, NO DIGESTERS

First year	1986	1988	1991	1993	1995	1999
Last year	1987	1990	1992	1994	1998	2020
New capacity, units						
70 MW feeder	0	0	0	0	1	1
58.0 MW C.C.	0	0	1	1	1	1
Cumulative MW						
Committed	16.1	21.5	21.5	21.5	12.0	12.0
Feeder	0.0	0.0	0.0	0.0	70.0	70.0
C.C.	0.0	0.0	57.7	57.7	57.7	57.7
Total	16.1	21.5	79.2	79.2	139.7	139.7
Largest unit	1.5	6.0	58.0	58.0	70.0	70.0
Secure MW	14.6	15.5	21.2	21.2	69.7	69.7
Capital costs, 1000$						
Feeder	$0	$0	$0	$0	$9,500	$0
C.C.	$0	$0	$54,000	$0	$0	$0
Total	$0	$0	$54,000	$0	$9,500	$0
Present worth	$0	$0	$54,000	$0	$6,823	$0
Cumulative	$0	$0	$54,000	$54,000	$60,823	$60,823
Surplus capacity, MW	0.5	0.2	-9.2	-11.2	28.5	25.2
Utility demand, MW	0.0	0.0	0.0	0.0	0.0	3.2
Energy generated, MWh/yr						
On digester gas						
on-peak	0	0	0	0	0	0
off-peak	0	0	0	0	0	0
On purchased fuel						
On-peak						
C.C.	0	0	64653	68530	85687	121824
Diesel	27431	29758	0	0	0	17
Off-peak						
C.C.	0	0	102450	108594	0	0
Diesel	43468	47155	0	0	0	0
Total	70900	76913	167104	177125	85687	121841

TABLE A-3
ALTERNATIVE 3A - 58MW CC, SINGLE UTILITY FEEDER, NO DIGESTERS
(Continued)

Energy purchased, MWh/yr						
On-peak	-0	0	0	·0	0	1
Off-peak	-0	0	0	0	135781	193074
Total	-0	0	0	0	135781	193075
Grand total	70900	76913	167104	177125	221469	314916
Error	-0	0	0	0	0	0
Heating requirements, MBtu/yr						
Total heating	33215	33215	33215	33215	33215	33215
on/off pk	52633	52633	52633	52633	52633	52633
Diesel heat	0	0	0	0	0	0
on/off pk	0	0	0	0	0	0
CC extraction	0	0	153936	163168	204017	290058
on/off pk	0	0	243929	258558	0	0
From boilers	85848	85848	0	0	52633	52633
Equivalent fuel	100998	100998	0	0	61921	61921
Annual costs, $1000/yr						
Electric utility						
Facilities	$0	$0	$0	$0	$0	$0
Demand	$0	$0	$0	$0	$0	$376
On-peak energy	($0)	$0	$0	$0	$0	$0
Off-peak energy	($0)	$0	$0	$0	$850	$1,209
Fuel adjustment	($0)	$0	$0	$0	$2,779	$3,952
Total electric	($0)	$0	$0	$0	$3,629	$5,537
Heating fuel	$379	$379	$0	$0	$232	$232
Engine fuel	$2,446	$2,654	$0	$0	$0	$1
Comb cycle fuel	$0	$0	$5,573	$5,907	$2,858	$4,063
Total fuel	$2,825	$3,033	$5,573	$5,907	$3,090	$4,296
O&M cost	$322	$430	$2,736	$2,736	$2,546	$2,546
Total cost	$3,147	$3,463	$8,309	$8,643	$9,266	$12,379
Present worth	$0	$0	$14,691	$12,952	$21,739	$62,048
Cumulative	$0	$0	$14,691	$27,643	$49,383	$111,430
TOTAL PRES. WORTH	$0	$0	$68,691	$81,643	$110,206	$172,254

SUMMARY PRESENT WORTH COST:
$1,000

Capital:	$60,823
Operating:	$111,430
Total:	$172,254

TABLE A-4

ALTERNATIVE 3B - 25.7 MW CC, DUAL UTILITY FEEDERS, NO DIGESTERS

First year	1986	1988	1991	1993	1995	1999
Last year	1987	1990	1992	1994	1998	2020
New capacity, units						
70 MW feeder	0	0	2	2	2	2
25.7 MW C.C.	0	0	0	0	1	1
Cumulative MW						
Committed	16.1	21.5	21.5	21.5	12.0	12.0
Feeder	0.0	0.0	140.0	140.0	140.0	140.0
C.C.	0.0	0.0	0.0	0.0	25.4	25.4
Total	16.1	21.5	161.5	161.5	177.4	177.4
Largest unit	1.5	6.0	70.0	70.0	70.0	70.0
Secure MW	14.6	15.5	91.5	91.5	107.4	107.4
Capital costs, 1000$						
Feeder	$0	$0	$20,100	$0	$0	$0
C.C.	$0	$0	$0	$0	$23,310	$0
Total	$0	$0	$20,100	$0	$23,310	$0
Present worth	$0	$0	$20,100	$0	$16,743	$0
Cumulative	$0	$0	$20,100	$20,100	$36,843	$36,843
Surplus capacity, MW	0.5	0.2	61.2	59.2	66.2	62.9
Utility demand, MW	0.0	0.0	14.9	16.9	12.2	30.9
Energy generated, MWh/yr						
On digester gas						
on-peak	0	0	0	0	0	0
off-peak	0	0	0	0	0	0
On purchased fuel						
On-peak						
C.C.	0	0	0	0	72870	73561
Diesel	27431	29758	60340	61152	12794	33267
Off-peak						
C.C.	0	0	0	0	0	0
Diesel	43468	47155	0	0	0	0
Total	70900	76913	60340	61152	85664	106828

TABLE A-4
ALTERNATIVE 3B - 25.7 MW CC, DUAL UTILITY FEEDERS, NO DIGESTERS
(Continued)

Energy purchased, MWh/yr						
On-peak	-0	0	4313	7378	23	15015
Off-peak	-0	0	102450	108594	135781	193074
Total	-0	0	106764	115972	135805	208088
Grand total	70900	76913	167104	177125	221469	314916
Error	-0	0	-0	-0	0	0
Heating requirements, MBtu/yr						
Total heating	33215	33215	33215	33215	33215	33215
on/off pk	52633	52633	52633	52633	52633	52633
Diesel heat	0	0	0	0	0	0
on/off pk	0	0	0	0	0	0
CC extraction	0	0	0	0	173499	175146
on/off pk	0	0	0	0	0	0
From boilers	85848	85848	85848	85848	52633	52633
Equivalent fuel	100998	100998	100998	100998	61921	61921
Annual costs, $1000/yr						
Electric utility						
Facilities	$0	$0	$0	$0	$0	$0
Demand	$0	$0	$1,748	$1,982	$1,430	$3,612
On-peak energy	($0)	$0	$128	$218	$1	$444
Off-peak energy	($0)	$0	$641	$680	$850	$1,209
Fuel adjustment	($0)	$0	$2,185	$2,374	$2,780	$4,260
Total electric	($0)	$0	$4,703	$5,254	$5,060	$9,524
Heating fuel	$379	$379	$379	$379	$232	$232
Engine fuel	$2,446	$2,654	$2,082	$2,110	$441	$1,148
Comb cycle fuel	$0	$0	$0	$0	$2,496	$2,520
Total fuel	$2,825	$3,033	$2,461	$2,489	$3,170	$3,900
O&M cost	$322	$430	$430	$430	$1,254	$1,254
Total cost	$3,147	$3,463	$7,593	$8,173	$9,484	$14,678
Present worth	$0	$0	$13,426	$12,247	$22,252	$73,570
Cumulative	$0	$0	$13,426	$25,673	$47,925	$121,494
TOTAL PRES. WORTH	$0	$0	$33,526	$45,773	$84,767	$158,337

SUMMARY PRESENT WORTH COST:
$1,000

Capital:	$36,843
Operating:	$121,494
Total:	$158,337

TABLE A-5

ALTERNATIVE 3B - 15 MW CC, DUAL UTILITY FEEDERS, NO DIGESTERS

First year	1986	1988	1991	1993	1995	1999
Last year	1987	1990	1992	1994	1998	2020
New capacity, units						
70 MW feeder	0	0	1	1	2	2
15.0 MW C.C.	0	0	1	1	1	1
Cumulative MW						
Committed	16.1	21.5	21.5	21.5	12.0	12.0
Feeder	0.0	0.0	70.0	70.0	140.0	140.0
C.C.	0.0	0.0	14.7	14.7	14.7	14.7
Total	16.1	21.5	106.2	106.2	166.7	166.7
Largest unit	1.5	6.0	70.0	70.0	70.0	70.0
Secure MW	14.6	15.5	36.2	36.2	96.7	96.7
Capital costs, 1000$						
Feeder	$0	$0	$9,500	$0	$10,600	$0
C.C.	$0	$0	$13,854	$0	$0	$0
Total	$0	$0	$23,354	$0	$10,600	$0
Present worth	$0	$0	$23,354	$0	$7,614	$0
Cumulative	$0	$0	$23,354	$23,354	$30,968	$30,968
Surplus capacity, MW	0.5	0.2	5.8	3.8	55.5	52.2
Utility demand, MW	0.0	0.0	2.4	4.4	21.4	40.0
Energy generated, MWh/yr						
On digester gas						
on-peak	0	0	0	0	0	0
off-peak	0	0	0	0	0	0
On purchased fuel						
On-peak						
C.C.	0	0	42513	42516	42523	42523
Diesel	27431	29758	22139	26012	33442	34806
Off-peak						
C.C.	0	0	0	0	0	0
Diesel	43468	47155	0	0	0	0
Total	70900	76913	64652	68527	75965	77329

TABLE A-5
ALTERNATIVE 3B - 15 MW CC, DUAL UTILITY FEEDERS, NO DIGESTERS
(Continued)

Energy purchased, MWh/yr						
On-peak	-0	0	1	3	9723	44513
Off-peak	-0	0	102450	108594	135781	193074
Total	-0	0	102451	108597	145504	237587
Grand total	70900	76913	167104	177125	221469	314916
Error	-0	0	-0	0	0	0
Heating requirements, MBtu/yr						
Total heating	33215	33215	33215	33215	33215	33215
on/off pk	52633	52633	52633	52633	52633	52633
Diesel heat	0	0	0	0	0	0
on/off pk	0	0	0	0	0	0
CC extraction	0	0	101222	101228	101246	101246
on/off pk	0	0	0	0	0	0
From boilers	85848	85848	52633	52633	52633	52633
Equivalent fuel	100998	100998	61921	61921	61921	61921
Annual costs, $1000/yr						
Electric utility						
Facilities	$0	$0	$0	$0	$0	$0
Demand	$0	$0	$280	$514	$2,501	$4,683
On-peak energy	($0)	$0	$0	$0	$287	$1,316
Off-peak energy	($0)	$0	$641	$680	$850	$1,209
Fuel adjustment	($0)	$0	$2,097	$2,223	$2,978	$4,863
Total electric	($0)	$0	$3,019	$3,417	$6,617	$12,072
Heating fuel	$379	$379	$232	$232	$232	$232
Engine fuel	$2,446	$2,654	$764	$898	$1,154	$1,201
Comb cycle fuel	$0	$0	$1,546	$1,546	$1,546	$1,546
Total fuel	$2,825	$3,033	$2,542	$2,676	$2,932	$2,979
O&M cost	$322	$430	$1,016	$1,016	$826	$826
Total cost	$3,147	$3,463	$6,577	$7,109	$10,376	$15,877
Present worth	$0	$0	$11,629	$10,653	$24,344	$79,582
Cumulative	$0	$0	$11,629	$22,281	$46,625	$126,208
TOTAL PRES. WORTH	$0	$0	$34,983	$45,635	$77,593	$157,175

SUMMARY PRESENT WORTH COST:
$1,000

Capital:	$30,968
Operating:	$126,208
Total:	$157,175

TABLE A-5

ALTERNATIVE 3B - 15 MW CC, DUAL UTILITY FEEDERS, NO DIGESTERS

First year	1986	1988	1991	1993	1995	1999
Last year	1987	1990	1992	1994	1998	2020
New capacity, units						
70 MW feeder	0	0	2	2	2	2
15.0 MW C.C.	0	0	0	0	1	1
Cumulative MW						
Committed	16.1	21.5	21.5	21.5	12.0	12.0
Feeder	0.0	0.0	140.0	140.0	140.0	140.0
C.C.	0.0	0.0	0.0	0.0	14.7	14.7
Total	16.1	21.5	161.5	161.5	166.7	166.7
Largest unit	1.5	6.0	70.0	70.0	70.0	70.0
Secure MW	14.6	15.5	91.5	91.5	96.7	96.7
Capital costs, 1000$						
Feeder	$0	$0	$20,100	$0	$0	$0
C.C.	$0	$0	$0	$0	$13,854	$0
Total	$0	$0	$20,100	$0	$13,854	$0
Present worth	$0	$0	$20,100	$0	$9,951	$0
Cumulative	$0	$0	$20,100	$20,100	$30,051	$30,051
Surplus capacity, MW	0.5	0.2	61.2	59.2	55.5	52.2
Utility demand, MW	0.0	0.0	14.9	16.9	21.4	40.0
Energy generated, MWh/yr						
On digester gas						
on-peak	0	0	0	0	0	0
off-peak	0	0	0	0	0	0
On purchased fuel						
On-peak						
C.C.	0	0	0	0	42523	42523
Diesel	27431	29758	60340	61152	33442	34806
Off-peak						
C.C.	0	0	0	0	0	0
Diesel	43468	47155	0	0	0	0
Total	70900	76913	60340	61152	75965	77329

TABLE A-5
ALTERNATIVE 3B - 15 MW CC, DUAL UTILITY FEEDERS, NO DIGESTERS
(Continued)

Energy purchased, MWh/yr						
On-peak	-0	0	4313	7378	9723	44513
Off-peak	-0	0	102450	108594	135781	193074
Total	-0	0	106764	115972	145504	237587
Grand total	70900	76913	167104	177125	221469	314916
Error	-0	0	-0	-0	0	0
Heating requirements, MBtu/yr						
Total heating	33215	33215	33215	33215	33215	33215
on/off pk	52633	52633	52633	52633	52633	52633
Diesel heat	0	0	0	0	0	0
on/off pk	0	0	0	0	0	0
CC extraction	0	0	0	0	101246	101246
on/off pk	0	0	0	0	0	0
From boilers	85848	85848	85848	85848	52633	52633
Equivalent fuel	100998	100998	100998	100998	61921	61921
Annual costs, $1000/yr						
Electric utility						
Facilities	$0	$0	$0	$0	$0	$0
Demand	$0	$0	$1,748	$1,982	$2,501	$4,683
On-peak energy	($0)	$0	$128	$218	$287	$1,316
Off-peak energy	($0)	$0	$641	$680	$850	$1,209
Fuel adjustment	($0)	$0	$2,185	$2,374	$2,978	$4,863
Total electric	($0)	$0	$4,703	$5,254	$6,617	$12,072
Heating fuel	$379	$379	$379	$379	$232	$232
Engine fuel	$2,446	$2,654	$2,082	$2,110	$1,154	$1,201
Comb cycle fuel	$0	$0	$0	$0	$1,546	$1,546
Total fuel	$2,825	$3,033	$2,461	$2,489	$2,932	$2,979
O&M cost	$322	$430	$430	$430	$826	$826
Total cost	$3,147	$3,463	$7,593	$8,173	$10,376	$15,877
Present worth	$0	$0	$13,426	$12,247	$24,344	$79,582
Cumulative	$0	$0	$13,426	$25,673	$50,017	$129,600
TOTAL PRES. WORTH	$0	$0	$33,526	$45,773	$80,068	$159,651

SUMMARY PRESENT WORTH COST:
$1,000

Capital:	$30,051
Operating:	$129,600
Total:	$159,651

WATER RESOURCES AUTHORITY
MASSACHUSETTS